



Carbon-free steel production

Cost reduction
options and usage
of existing gas
infrastructure

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Carbon-free steel production: Cost reduction options and usage of existing gas infrastructure

The steel sector is one of the most challenging sectors to decarbonise and has recently received special attention owing to the potential use of low-carbon hydrogen (green and blue) to reduce its fuel combustion and process-related carbon emissions. This report addresses concerns that might arise while evaluating the potential and limitations of the future role of hydrogen in decarbonising the iron and steel industries.

The report provides a comprehensive overview of current technical knowledge, (pilot) projects and road maps at national and EU level. This information is supplemented by previously published indicative price projections for the various steel production routes and a long-term study, analysing the evolution of the global steel sector up until 2100.

AUTHORS

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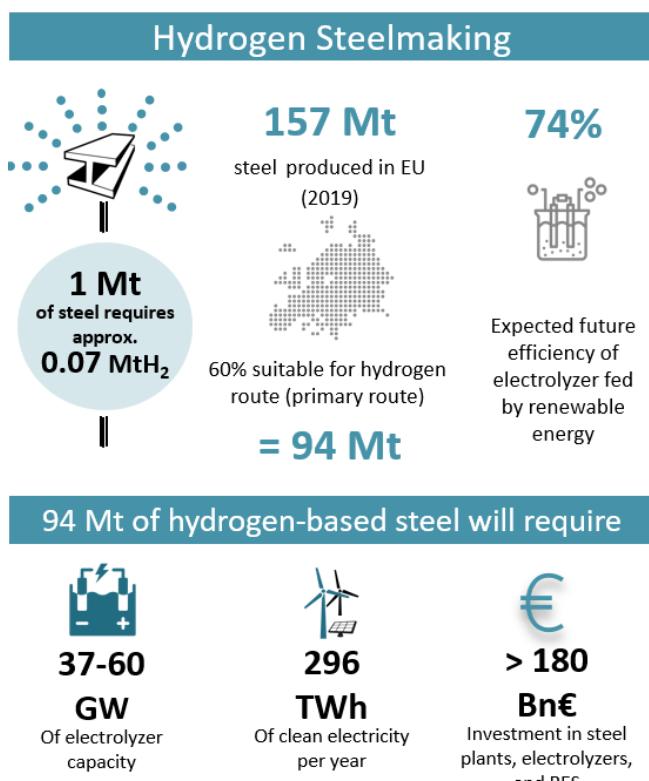
Executive summary

The steel sector is one of the most challenging sectors to decarbonise and has recently received special attention on account of the potential use of low-carbon hydrogen to reduce its fuel combustion and process-related carbon emissions. This report addresses concerns that might arise while evaluating the potential and limitations of the future role of hydrogen in decarbonising the iron and steel industries.

The sector is one of the pillars of the European industry and job market, supporting approximately 2.7 million (direct and indirect) jobs. In 2019, the production of crude steel in Europe was 157 Mt, which accounted for 4 % of the greenhouse Gas (GHG) emissions in Europe. Investment decisions are challenging since margins are tight and the competition is fierce. The slowdown due to the pandemic has worsened the situation, resulting in a reduction in demand for steel products in 2020. In Europe alone, prices have fallen nearly 30 % since 2018. Furthermore, manufacturing sectors are now including carbon neutrality in their strategies, putting pressure on steel producers to embrace these commitments while remaining competitive and maintaining their place in the supply chain.

In Europe, some blast furnaces are almost 25 years old, making them fit candidates for technology replacement, while others have recently undergone refurbishments that entailed large investments. In the coming decades, this condition could open a window of opportunities to replace current assets with cleaner, novel technologies. Nevertheless, the decision to shift to a cleaner route is site-specific and will come at different times.

Decarbonising the steel sector in Europe



The iron and steel sector is part of the hard to decarbonise sectors together with cement, aviation, refineries and the petrochemical sectors. Currently, 60 % of steel produced in Europe originates from the integrated blast furnace/basic oxygen furnace route (BF/BOF), which emits around $1.9 \text{ tCO}_2/\text{t}_{\text{steel}}$. Other routes, for instance, the natural-gas-based NG-DRI and Scrap-EAF generate lower emissions, with $1.4 \text{ tCO}_2/\text{t}_{\text{steel}}$ and $0.4 \text{ tCO}_2/\text{t}_{\text{steel}}$, respectively.

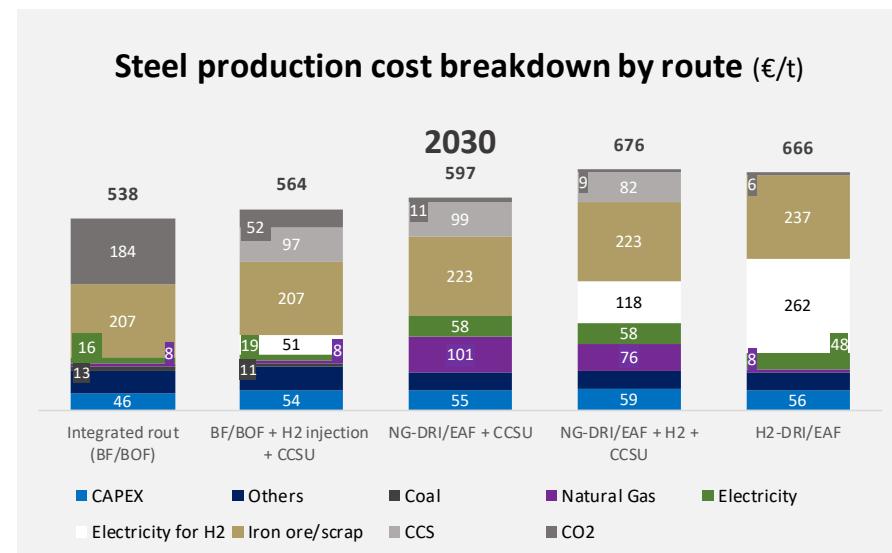
Sixty per cent (94 Mt) of the total steel produced in Europe originates from the BF/BOF route and is more suitable for the hydrogen direct reduction route (H-DRI). Estimates suggest that 94 Mt of 'green steel' would require approximately 37-60 GW of electrolyser capacity, producing approximately 6.6 Mt of hydrogen per year. As a reference, the EU Hydrogen Strategy aims to have 40 GW of electrolyser capacity installed within the EU by 2030. The authors estimate that these electrolyzers would

consume approximately 296 TWh of green electricity per year; as a reference, Germany produced in total 176 TWh of green electricity in 2020.

Several H-DRI projects have been backed by iron and steel producers across Europe. The companies involved expect the technology to reach commercialisation at large capacities by 2035. This

transition will create demand for low-carbon hydrogen ($60\text{-}80 \text{ kgH}_2/\text{t}_{\text{steel}}$). This hydrogen could be supplied by installing electrolyzers on-site, in which case the storage of hydrogen could guarantee an uninterrupted hydrogen supply. A second alternative is the use of pipelines to link the hydrogen production sites with consumption locations. Both methods are challenging and the prevalence of one over the other depends strongly on the location of the steel plant and access to low-cost renewable energy.

Other decarbonisation routes, such as carbon capture and storage (CCS), face technical and non-technical challenges, such as public acceptance and regulatory hurdles. For example to store the annual CO_2 emissions of the current steel sector (163 Mt CO_2), over 100 projects with the initial annual storage capacity of the Northern Lights project in Norway would be required.



Comparing the expected cost per ton of steel among the potential production routes, the authors' calculation shows that, by 2030, the innovative routes will increase the end-product cost by a premium of 5 to 24 %, with an abatement cost of €73–€166 per ton of CO_2 , compared with the integrated BF/BOF route.¹

Steel production and recycling forecast

The authors previously performed a study on the long-term global outlook for steel. This study, which is also presented in a summarised format in this report, analysed 13 world regions on the basis of an integrated steel production and recycling model. The study found that on a global scale demand for steel will increase and stabilise around the year 2070. The global demand for flat steel (e.g. for car manufacturing and so-called white products) is projected to increase by 87 %, while the demand for long steel products (e.g. for infrastructure and construction) will only increase by 30 %. The availability of steel scrap re-entering the production cycle will increase by 167 % and play an important role in decarbonising the long steel sectors globally.

Hydrogen production

The technology used to produce hydrogen determines the carbon emissions associated with the fuel. A hydrogen colour convention has been widely accepted; these hydrogen colours include, but are not limited to, grey (from natural gas reforming), green (from Renewable Energy Sources (RES)), blue (from fossil fuels with CCS/U) and turquoise (from natural gas pyrolysis).

The production of low-carbon hydrogen in the EU depends on the availability of renewable energy sources (RES), and the feasibility and availability of CCS and carbon capture and utilisation (CCU) applications. Considering the increasing hydrogen demand in Europe, the limited potential of new wind and solar power generation installations, and the need for other sectors to decarbonise by

¹ The calculation assumes an EU ETS of €84 /ton of CO_2 in 2030 for all production routes (for 2050 price comparisons see Figure 15).

consuming carbon-free electricity (such as transport and heating), it is most likely that hydrogen imports will play a relevant role as well. Currently, Europe consumes approximately 9 Mt of hydrogen annually, which is almost exclusively produced by natural-gas-based steam methane reforming. Future hydrogen production within the borders of the European Union (EU) is being championed by the '2×40' initiative. According to the European Commission's hydrogen strategy, it will be possible to produce 10 Mt of green hydrogen (of 333 TWh_{H₂}) by 2030.

Hydrogen handling infrastructure

Hydrogen infrastructure describes the physical links between the points of production and consumption. It comprises long and short-distance pipelines, transport by ship or road, terminal stations, long and short-term storage facilities, and filling stations. Currently, the existing hydrogen transport infrastructure is one of the main bottlenecks in the transition to sustainable hydrogen use in the EU. In Europe, there are roughly 2 000 km of dedicated hydrogen pipelines distributed among four countries: Belgium (613 km), Germany (376 km), France (303 km) and the Netherlands (237 km). By way of comparison, there are approximately 260 000 km of natural gas transport pipelines.

Currently, EU gas transmission owners are conducting studies and tests to find out which parts of their infrastructure can be reused for transporting hydrogen. This is the case for the Europe Hydrogen Backbone initiative proposed by several gas transmission operators, aiming in the first phase to have 6 800 km of hydrogen pipelines available by 2030 and 23 000 km by 2040, of which 75 % would consist of reused natural gas pipelines. Most of the upgrades involve the compressor stations, valves, fittings, metering stations and storage tanks. Compared with building new pipelines, these costs are relatively small. Investment costs for new hydrogen pipelines can vary significantly depending on location, material and regulation (0.93 – 3.28 M€/km). However, in both cases of newly constructed hydrogen and repurposed natural gas pipelines, compressor installations will have to be upgraded to increase the transportation capacity (flow volume) over time with growing hydrogen demand. Important to mention is that the development of dedicated hydrogen pipelines will likely be concentrated in areas with high industrial demands (for feedstock or high-temperature fuel), which are already heavily concentrated in industrial clusters.

Hydrogen can also be transported by ship. However, due to its low energy density, it will have to be liquefied, which implies high energy losses. Another way to transport hydrogen in large quantities overseas is by transforming it into a carrier with higher densities, such as ammonia or binding it in liquid organic hydrogen carriers (LOHCs). This requires special handling at the terminals to convert hydrogen into these carriers and back to hydrogen at the destination. The conversion costs, potential emissions (e.g. NO_x in the case of ammonia), as well as matters of safety and social acceptance must be considered.

Hydrogen can be blended with natural gas at limited percentages of 5 %-20 %, while higher shares of up to 30 % are being investigated. Blending percentages are case-specific and may enable decentralised renewable hydrogen production in small amounts during a transitional phase. However, with larger volumes of hydrogen, it is economically advantageous to use a dedicated route as blending becomes less efficient. Blending degrades the quality of the gas consumed. This might lead to fragmentation of the internal market if different standards of blending are accepted by Member States. The impact on emissions is also limited, for instance: blending 10 % hydrogen leads to a reduction of only 3 % in CO₂ emissions.

Increasing volumes of hydrogen coming from variable renewable energy sources will not be available at constant rates. Thus, a matching storage capacity similar to the one used to balance the natural gas grid and market applies. For low volumes of hydrogen applications, hydrogen can be stored in tanks with high discharge rates and efficiencies. When compressed at 700 bars, the energy density is only 15 % of gasoline, requiring six times more volume to store the same amount of energy. Long-duration storage facilities are required to overcome seasonal shortage if hydrogen is to be used as feedstock supply or high temperature heat fuel in continuous operations for industries.

Depleted gas or oil reservoirs and aquifers require careful analysis and preparation to ensure proper locking mechanisms are in place to prevent gas leaks. Besides gas volume losses, special care has to be taken when repurposing depleted gas fields, caverns or aquifers for storing hydrogen in pure or blended form. Corrosion and weaknesses in the sealings of the borehole can occur due to the formation of hydrogen sulphide, which is caused by microbiological reactions within the aquifer. Bacterial growth can lead to further volume losses. A study run for the Netherlands Enterprise Agency analyses the risks of storing hydrogen underground in greater depth (DBI Gas- und Umwelttechnik GMBH, 2017).

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List of acronyms

ATR	Auto Thermal Reforming
BF	Blast Furnace
BOF	Basic Oxygen Furnace
CEN	European Committee for Standardisation
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilization
DRI	Direct Reduced Iron
DRI/EA	Direct Reduced Iron integrated with an Electric Arc
EAF	Electric Arc Furnace
EII	Energy Intensive Industries
GHG	Greenhouse Gas
HHV	High Heating Value
LCOT	Levelised Cost of Transmission
LHV	Low Heating Value
SMR	Steam Methane Reforming
TEN-E	Trans-European Network - Energy

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1. Introduction

The steel sector is one of the most challenging sectors to decarbonise and has recently received special attention owing to the potential use of low-carbon hydrogen (green and blue) to reduce its fuel combustion and process-related carbon emissions. This report aims to address several concerns that have arisen while evaluating the potential and limitations of the future role of hydrogen in decarbonising the iron and steel industries.

The scope of this study, in terms of timing and budget, is limited and it therefore focuses on providing a comprehensive overview of the current technical knowledge, (pilot) projects and road maps at national and EU level. This information is supplemented by indicative price projections for the various steel production routes (see Chapter 2 and Figure 15) and a long-term study, analysing the evolution of the global steel sector up until 2100 (see Chapter 3), both based on readily available data and scientific reports from Vito.

More in-depth analysis is required to gain a deeper understanding of the barriers to and enablers of the up-take of hydrogen in energy intensive industries (EIs) in general and the iron and steel sector in particular. Here the authors' team would also like to refer to the project 'AidRES - Advancing industrial decarbonisation by assessing the future use of renewable energies in industrial processes'² which was launched in January 2021 and will create a database of the main EIs in Europe, including current and future energy and feedstock needs and the mapping of renewable energy needs in high spatial resolution.

The tender document provides a list of specific questions as well. For easier orientation, the following text boxes provide an overview of how far this report addresses those questions and in which chapter the relevant information can be found.

² Aid RES – Advancing industrial decarbonisation by assessing the future use of renewable energies in industrial processes, NUMBER –ENER/2020/OP/0011-C2/SER/2019-569/SI2.840687, (Pilot Project No. 32027714 of the European Parliament) - Project Officer: Eric Lecomte (DG ENER), Consortium Project Manager: Frank Meinke-Hubeny (Vito).

QUESTIONS FROM THE TENDER

- Pathways and timelines for coal substitution with hydrogen in steelmaking.
- Hydrogen direct reduction (H-DRI) will need the development of large infrastructure (see Figure 13) and competes against CCS and CCU alternatives, as well as emerging solutions such as natural gas pyrolysis and iron ore electrolysis (see section 2.4).
- The steel sector will compete with other sectors (e.g.: petrochemical, transport) for the available low-carbon hydrogen. Thus, the deployment of new technologies in this sector depends not only on technology readiness but also on hydrogen supply potential, demand in other sectors, financial incentives and business strategies. A clear pathway needs more complex and robust models to deal with the barriers as well as enablers for the plant specific transformation.
- From an end product cost point of view Figure 15 provides indicative cost projections for each considered production route for the year 2020, 2030 and 2050.
- The potential of using existing gas infrastructure for the transport of hydrogen.
- Sections 5.2 Hydrogen Backbone and 5.3 Transmission and distribution provide an overview of techno-economic parameters as well as insights from current (pilot) projects.
- Energy prices and CAPEX reduction needed to make the H-DRI route an attractive business case.
- There are several parameters that influence the competitiveness of H-DRI such as electricity prices, electrolyser CAPEX and CO₂ emissions prices. An overview of the production cost breakdown is given in Figure 15, and the assumptions used are listed in Techno-economic assumptions, including the expected CAPEX reductions in key technologies, such as electrolyzers.
- Technical, financial and regulatory barriers for large-scale deployment of hydrogen-based steel production.
- Insights into technical aspects to be resolved specially in the case of hydrogen transport, as well as in the case of carbon storage are addressed in section 5.1. The main parameters influencing the hydrogen price (€/kgH₂) are the electricity price and electrolyzer CAPEX, since DRI is a mature technology (see Figure 13).
- Hydrogen needed across all the sectors to enable a cost-efficient transition towards carbon-neutrality in Europe by 2050.
- Hydrogen must reach a competitive price to make low-carbon production routes financially viable. This prices vary from sector to sector and case to case. Hence, sectorial analysis as well as a cross-sectorial global perspective are necessary to identify the most cost-efficient alternatives to reach full decarbonisation.
- Several projects, joint ventures and research efforts aim to solve this situation. Among such studies the AidRES project, which focuses on assessing the future use of renewable energies in industrial processes towards full decarbonisation.

QUESTIONS FROM THE TENDER

- The possible amount of hydrogen generated within the EU.
- The electricity available to produce green hydrogen within Europe is not only subject to the potential for renewable energy sources (RES) within the EU, but also will be impacted by the use of the generated green electricity. The European green deal prioritizes direct electrification over other alternatives, because of the better energy efficiency (no conversion losses), which will compete with the so-call indirect electrification (such as hydrogen production from green electricity). A more in-depth energy system analysis (model application) is needed to gain better insights and supply and demand projections.
- The EU Hydrogen strategy foresees the production of 10Mt of green hydrogen by 2030, while Hydrogen Europe estimates a total of 7.4Mt (including imports). FCH-JU vision for Europe allocates approx. 4 Mt of green hydrogen for the steel sector by 2050.
- Figure 13 provides a high-level calculation for the hydrogen required to decarbonise the coal-based production route with a hydrogen based production route.

- Hydrogen production onsite or centralized.
- The decision for on-site production versus centralized production will likely be plant-specific: the geographical location of the existing blast furnaces, access to RES, the existing power grid and natural gas infrastructure with conversion potential are important factors to determine whether captive or merchant hydrogen production is more advantageous (see Figure 2 and sections 4.2 and 4.3).
- In general one can say that hydrogen transmission pipelines can transport 10 to 20 times more energy over long distance at the same cost compared to high voltage power cable (see Table 4).
- DECHEMA estimates that access to low-carbon electricity is the main bottleneck in the use of hydrogen in the European chemical sector, which is estimated to use 500 - 1 400 TWh in 2030 and 2 000 – 4 500 TWh in 2050 of low-carbon electricity to produce hydrogen. Therefore, the chemical industry is set to be an important competitor for low-carbon hydrogen.

- Hydrogen blending and hydrogen dedicated pipelines.
- There are technical limitations for hydrogen blending into the natural gas network – see Chapter 5.4
- Significant investments are needed to increase the hydrogen blending level.
- Regulatory alignment is needed among the country gas operators regarding the threshold of hydrogen blending.

- Technical requirements for hydrogen pipeline transport.
- Chapter 5 is dedicated to the requirements for hydrogen transport

2. Steel production

Takeaways

- Steel manufacturing faces challenges from regulatory decarbonisation targets and steel product consumers -e.g. car manufacturers who aim to decarbonise their supply chain- to radically transform their production routes towards carbon-neutrality.
- Existing assets, such as blast furnace ovens, are relatively easy to refurbish and can be kept operational at low costs, which can hinder the transition to cleaner steel technologies such as hydrogen-based DRI.
- Europe produces approximately 157 Mt of steel, of which 60% (94 Mt) originates from the coal-based blast furnace (BF/BOF) route and is more suitable for the hydrogen direct reduction route (H-DRI).
- One can estimate that 94 Mt of 'green steel' would require approximately:
- 37-60 GW of electrolyser capacity (as a reference, the EU Hydrogen Strategy aims to have 40 GW installed within the EU by 2030).
- 296 TWh of green electricity (as a reference, Germany produced 176 TWh of green electricity in 2020).
- Other decarbonisation routes such as carbon capture and storage (CCS) face non-technical challenges like public acceptance and regulatory hurdles. To store the current CO₂ emission of the steel sector (163 MtCO₂), over 100 projects with the initial annual storage capacity of the Northern Lights project in Norway would be required.
- The authors' calculation show that by 2030, the alternative routes will increase the end product cost by a premium of 5-24%, with an abatement cost of €73-€166 per ton of CO₂ (compared with the integrated route BF/BOF).
- Natural gas pyrolysis and iron electrolysis are alternatives that might produce low-carbon steel but have still a low level of implementation readiness.

Steel is a central input material for many products in the European economy, positioning the iron and steel sector with close links to several other industries in manufacturing or construction sectors. Production of steel was responsible for 4% of greenhouse gas emissions in Europe (EU28) in 2018. The sector is part of the hard to decarbonise sectors together with cement, aviation, oil refineries and petrochemical sectors, which makes it imperative for Europe to reach its GHG reduction targets.

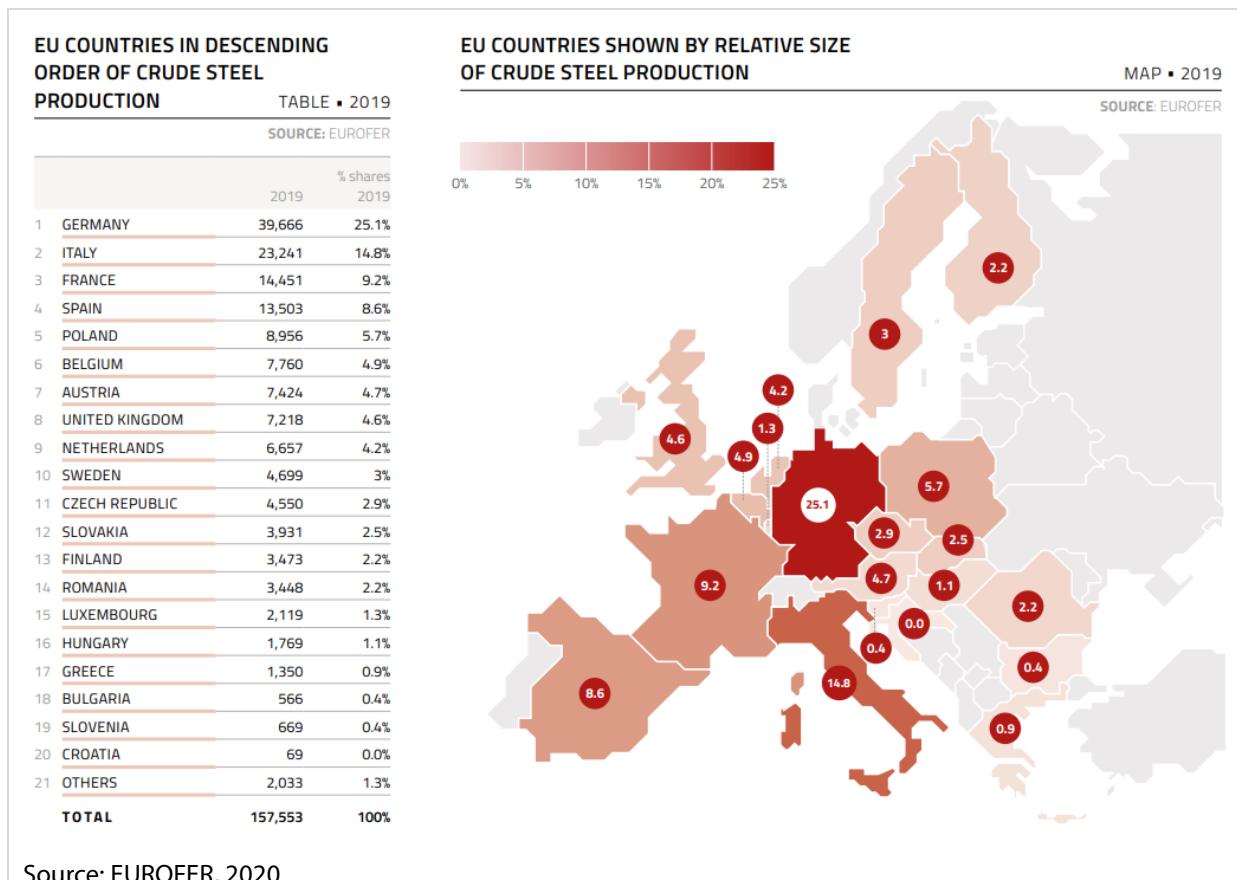
Currently, 60% of the steel produced in Europe originates from integrated blast furnace/blast oxygen furnace route (BF/BOF) which emits around 1.9 tCO₂/t_{steel}. To avoid these emissions, the direct reduction of iron ore (DRI) based on 100% low-carbon hydrogen (H-DRI) seems to be a promising production route. Several challenges must be addressed for large-scale adoption of this innovative route, such as the production of the required amount of hydrogen and necessary infrastructure besides the steel production facility such as electrolyser, wind, and solar power plants and hydrogen pipelines. In addition, technical requirements have to be met to enable alternative pathways to further decarbonise the steel sector employing carbon capture & storage (CCS) and utilisation (CCU). Also, fully electrified steel production routes such as iron ore electrolysis are promising technologies on the road to clean steel.

2.1. Steel production in Europe - Overview

In 2019, the production of crude steel in the world was 1 870 Mt of which Europe produced approximately 8.5% (World Steel Association, 2020). This took place mostly in Germany, Italy and France where half of the steel within Europe was manufactured as shown in Figure 1. Understanding the geographical spread of the production sites (see Figure 2) is relevant for identifying the sites and regions that can initiate the transition towards low carbon steel production routes. Specifically, in the case of the Blast Furnace – Basic Oxygen Furnace (BF/BOF) production facilities, which account for 60% of the steel made in Europe (Roland Berger, 2020), are good candidates to invest in new technologies in order to comply with the greenhouse gas (GHG) emission targets set for the sector in the coming decades. On the other hand, the Electric Arc Furnace (EAF) sites are wider distributed across Europe and are mostly dedicated to the production of steel of lower quality from scrap using grid electricity. In this regard, it is important to highlight that the large majority of the GHG emissions of the EAF route are indirect emissions accounted for in the power sector. Thus, decarbonising the EAF route requires the decarbonisation of the power sector. This is a further relevant point to guarantee low-carbon steel production within Europe, considering also that EAF is part of cleaner routes such as the natural gas direct reduction (NG-DRI) in combination with carbon capture and the hydrogen direct reduction (H-DRI).

The steel sector is one of the pillars of the European industry and the job market. EUROFER estimates that a total of 2.7 million jobs are supported by the industry, out of which 12.5% are direct jobs and the remaining 87.5% are indirect and induced jobs (EUROFER, 2020). In the last decade, the total number of direct jobs decreased by approximately 40 000, which has a similar trend to the total crude steel production over the same period. This can also be seen in the net trade balance of finished products, which shrunk from nearly 10 Mt in 2010 to almost - 5 Mt in 2019, making Europe a net importer of finished steel products (EUROFER, 2020).

Figure 1. Crude steel production in Europe by country in 2019



Source: EUROFER, 2020.

Depending on the production route, steel is divided into primary steel, originating mostly from iron ore which is traditionally being produced in a blast furnace/basic oxygen furnace route (BF/BOF), and secondary steel, originating mostly from recycled steel and which is traditionally being produced in an electric arc furnace (EAF). Each route produces different qualities of steel. The primary steel generally delivers higher quality since it does not deal with impurities from recycled materials as is the case in secondary steel. A second dimension is the steel type which can be flat or long steel. Flat steel products are made from steel slabs and require high-quality steel or iron as input. Typical applications for this kind of high-quality steel are the automotive or aviation sectors. Conversely, long steel products are made from blooms or billets, with lower quality. Long steel products are for example utilised in infrastructure and construction projects. Figure 3 shows the distribution of steel production by finished product in the EU in 2019.

Figure 2. Map of EU production sites

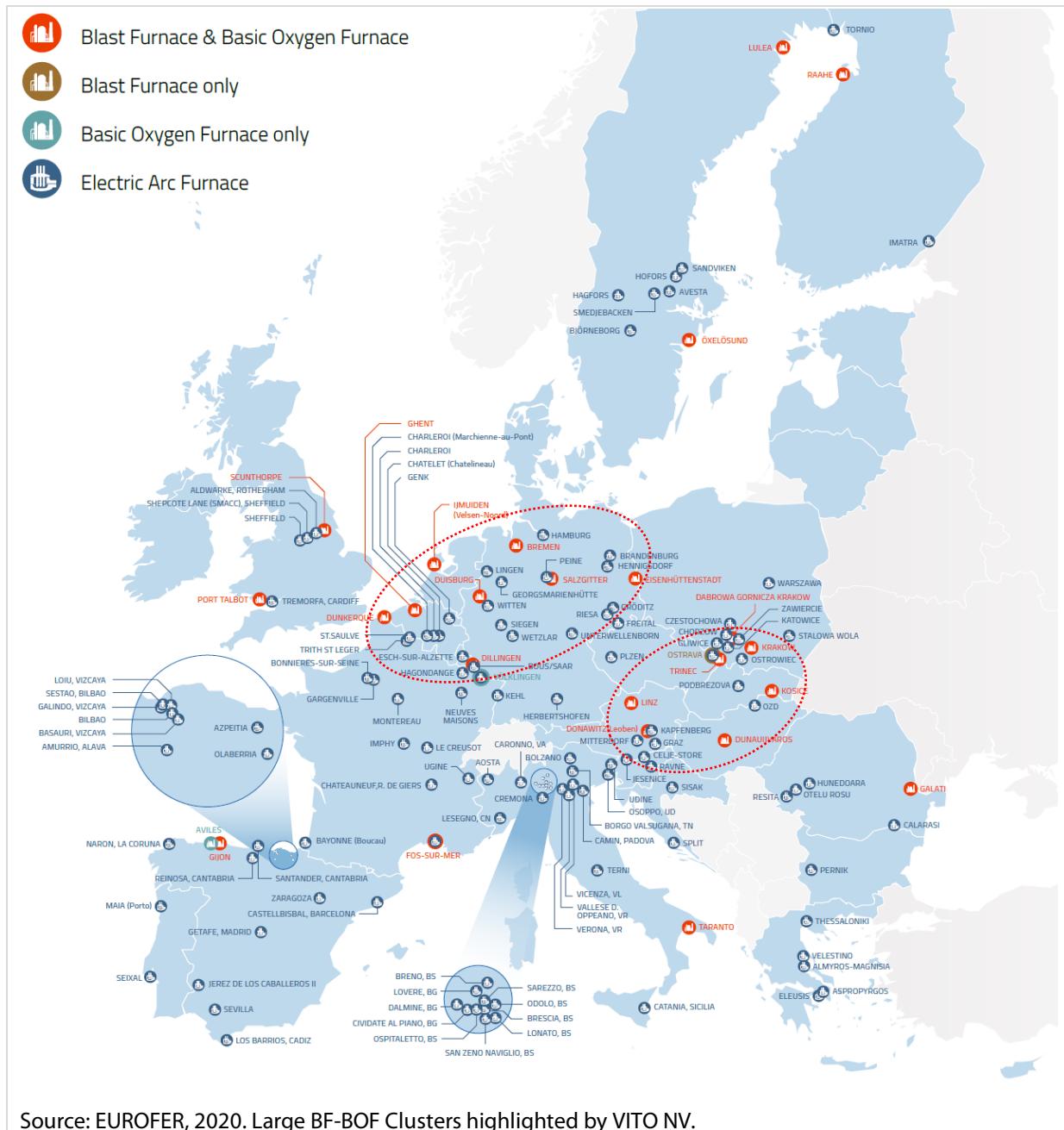


Figure 3. EU finished steel production in 2019, by product category

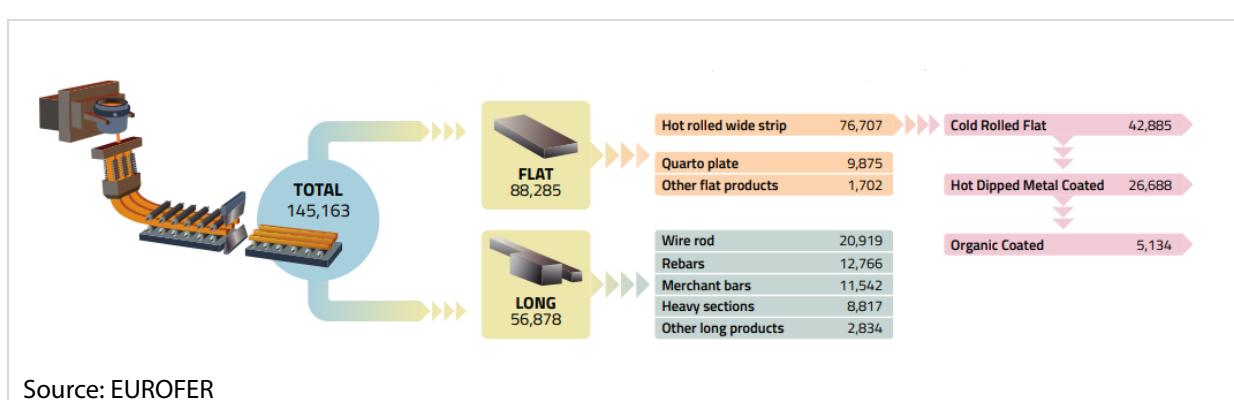
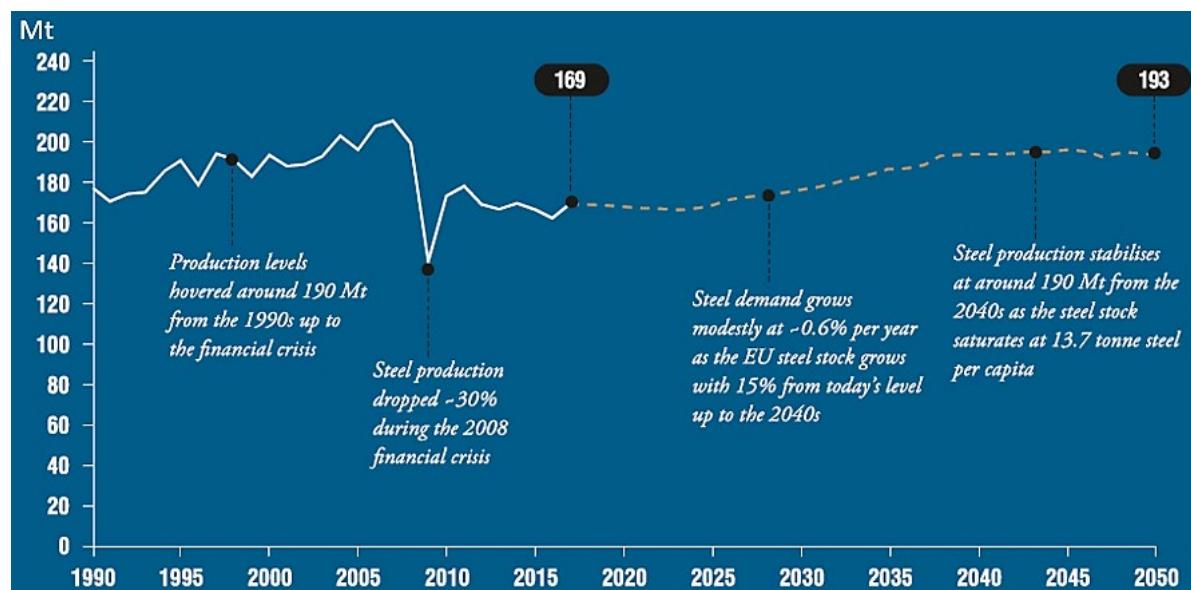


Figure 4. EU steel production in a baseline scenario to 2050



Source: Material Economics based on EUROFER (2018), World Steel (1990–2018), and Pauliuk et al. (2013).

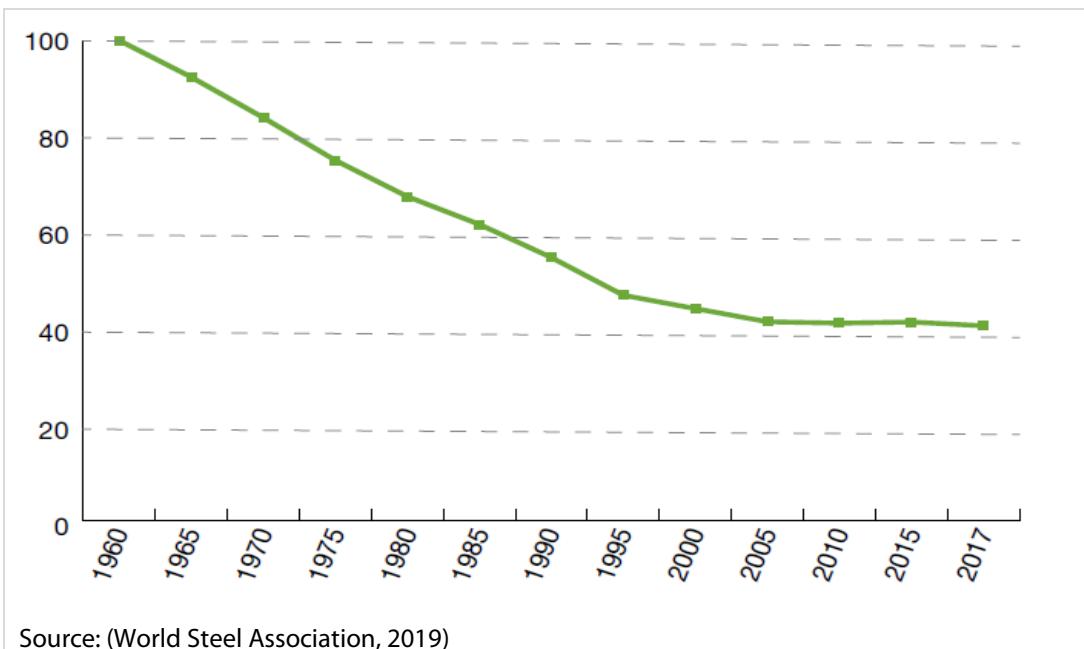
Figure 4 shows a forecast of the steel production within the EU up to the year 2050 according to Material Economics, which is expected to stabilise around 190 Mt, which corresponds to a saturation of approximately 13.7 tonne steel per capita.

Steel and steel scrap are globally traded commodities; to gain further insights into the dynamics of the global steel sector in the coming decades a case study based on a global steel model has been included in this report, see Chapter 3 for more details.

2.2. Established steel production paths

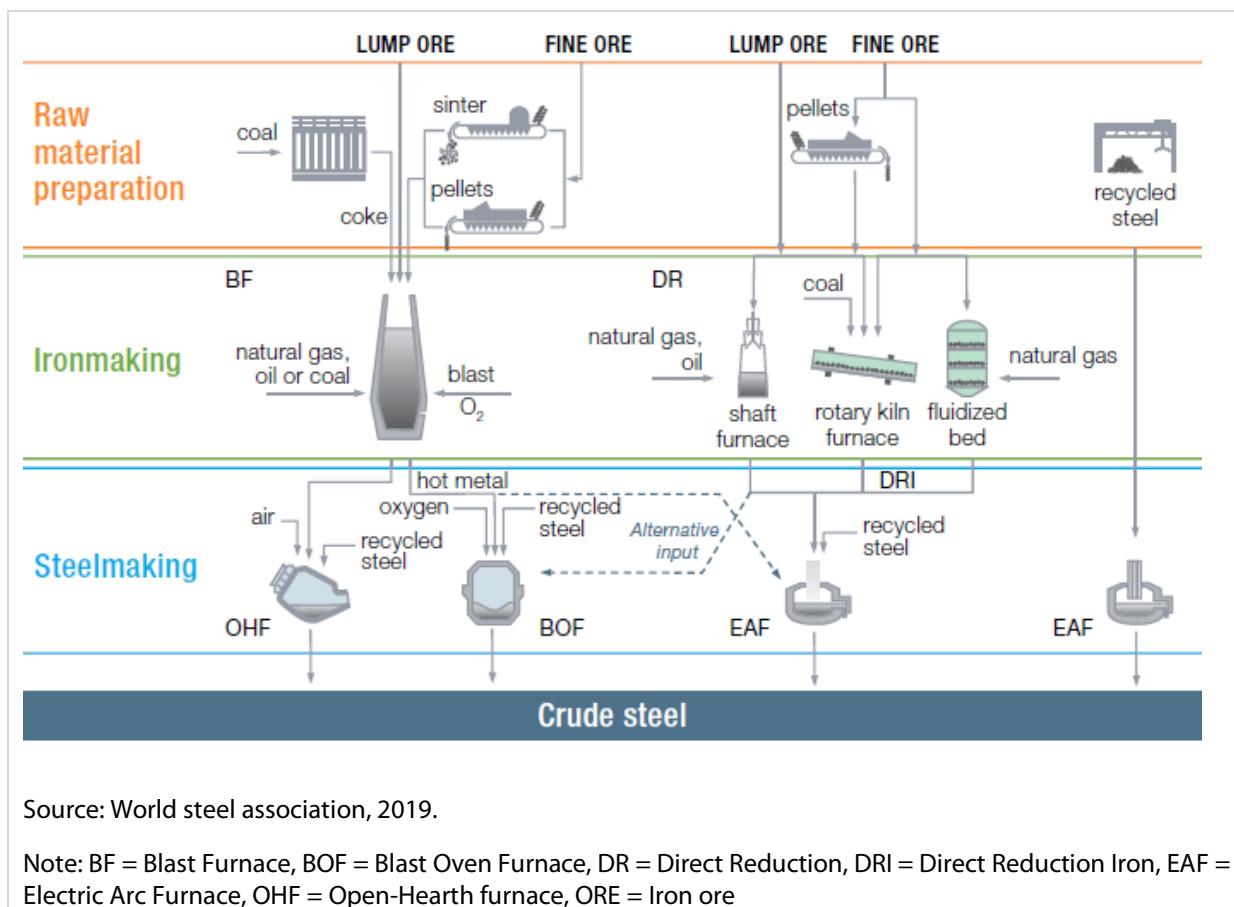
The iron and steel sector is one of the main sectors in Europe and it is intrinsically embedded with many other sectors of the economy such as the automotive industry, construction and machinery. At the same time, steel production is one of the world's most polluting industry, accounting for 7% of global emissions (Grattan Institute, 2020) of which 4% in EU28 in 2018 (EUROSTAT, 2019). It is a highly energy-intensive sector, consuming 22% of the worldwide industrial energy demand – about 8% of global total final energy, which makes it sensitive to fuel price volatility, considering that energy weights between 10-40% in the total production cost (IEA, 2020), (World Steel Association, 2019). The World Steel Association argues that currently, the average energy intensity is 20 GJ/t_{steel}, and that there is room for improvements in terms of energy efficiency of 15-20% (World Steel Association, 2020).

Figure 5. Indexed energy consumption by a ton of crude steel production



Currently, there are two main steel production routes: Blast Furnace – Basic Oxygen Furnace (BF/BOF) and Electric Arc Furnace (EAF). Additionally, Direct Reduced Iron integrated with an Electric Arc (DRI/EA) contributes to a lesser extent to global production. In Europe, the DRI route is less conventional as it relies on access to cheap natural gas. The major DRI producers are in the Middle East, India, and Russia (MIDREX, 2018). In the case of the BF/BOF route, iron ore and coal are the main raw materials. The majority of which are pre-processed to obtain sinter and pellets from iron ore and coke from coal. After being transformed, coke and sinter (or pellets) go to the Blast Furnace, where the iron ore is reduced to iron by removing oxygen. The resulting pig iron is processed into crude steel by the BOF. At this stage, high-quality scraps of iron can be added to increase recycling rates. In Figure 6 the most common routes for crude steel production are illustrated. Finally, the crude steel is processed further into rolls and sheets and can be finished by galvanisation, tin plating, or lacquering if required. The finishing process of crude steel is the same for all the routes (BF-BOF, DRI-EA, EAF, etc.).

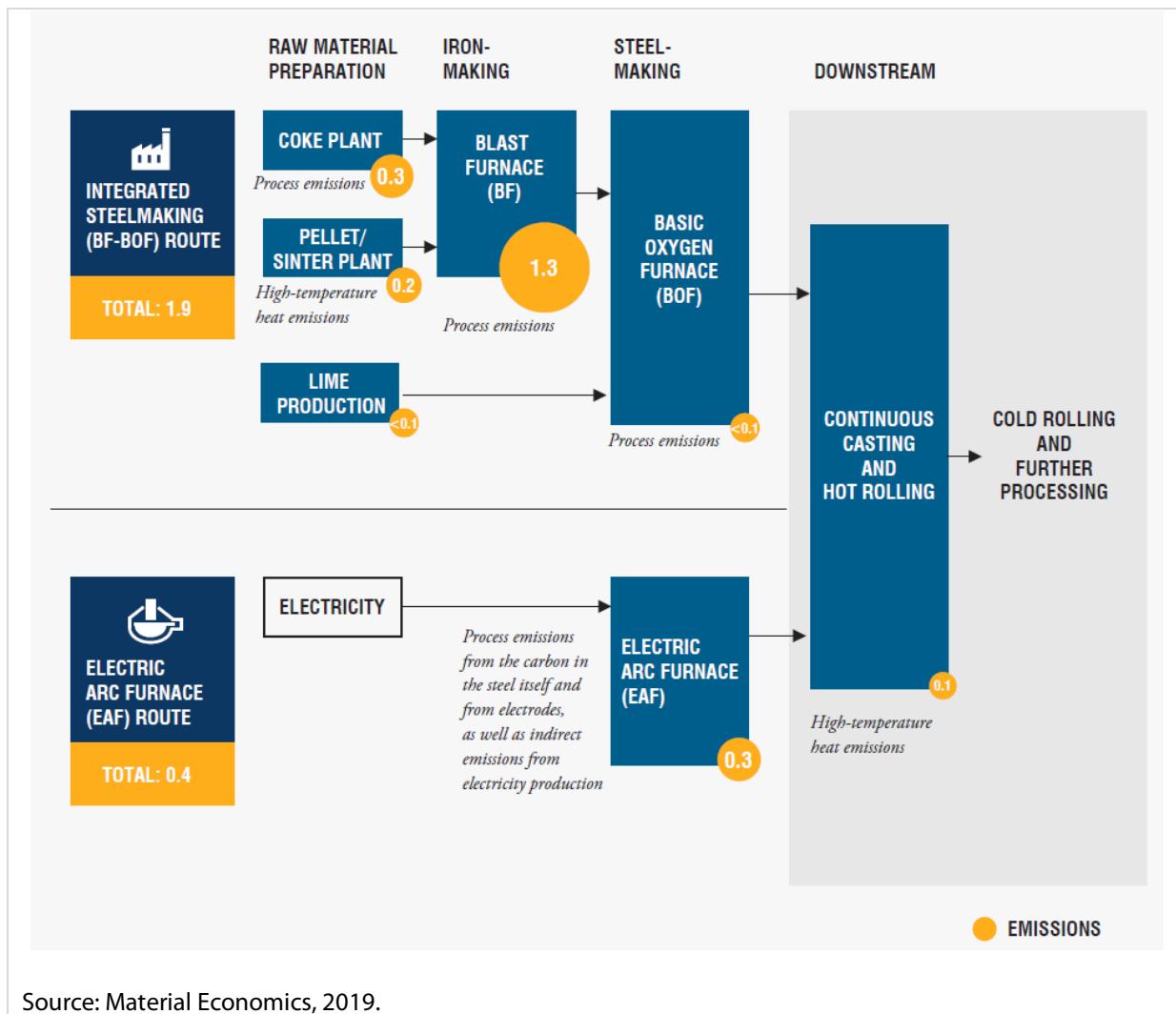
Figure 6. Overview of different steelmaking routes



In steelmaking, process emissions are related to the combustion of fossil fuels and chemical reactions. There are several CO₂ emission sources in the process (see Figure 7), and each route has a different emission footprint. The most carbon-intensive path is the coal-DRI/EAF, which is estimated to emit 2.4 tCO₂/t_{steel}, compared to 2 tCO₂/t_{steel} in the case of BF-BOF, and 1.4 tCO₂/t_{steel} and 0.4 tCO₂/t_{steel} for NG-DRI/EA and Scrap/EA, respectively (Ellis & Bao, 2020)³. Since the process has evolved considerably in the last centuries, nowadays it is a highly integrated process where outputs of one step are used as inputs in consecutive steps. These links between the process building blocks offer opportunities for improvements in energy efficiencies and feedstock intensity. However, it also acts as a disadvantage because it is difficult to implement changes in one part of the process without having implications elsewhere.

³ CO₂ emissions include estimated indirect emission from power grid in this literature source.

Figure 7. CO₂ emissions from steel production



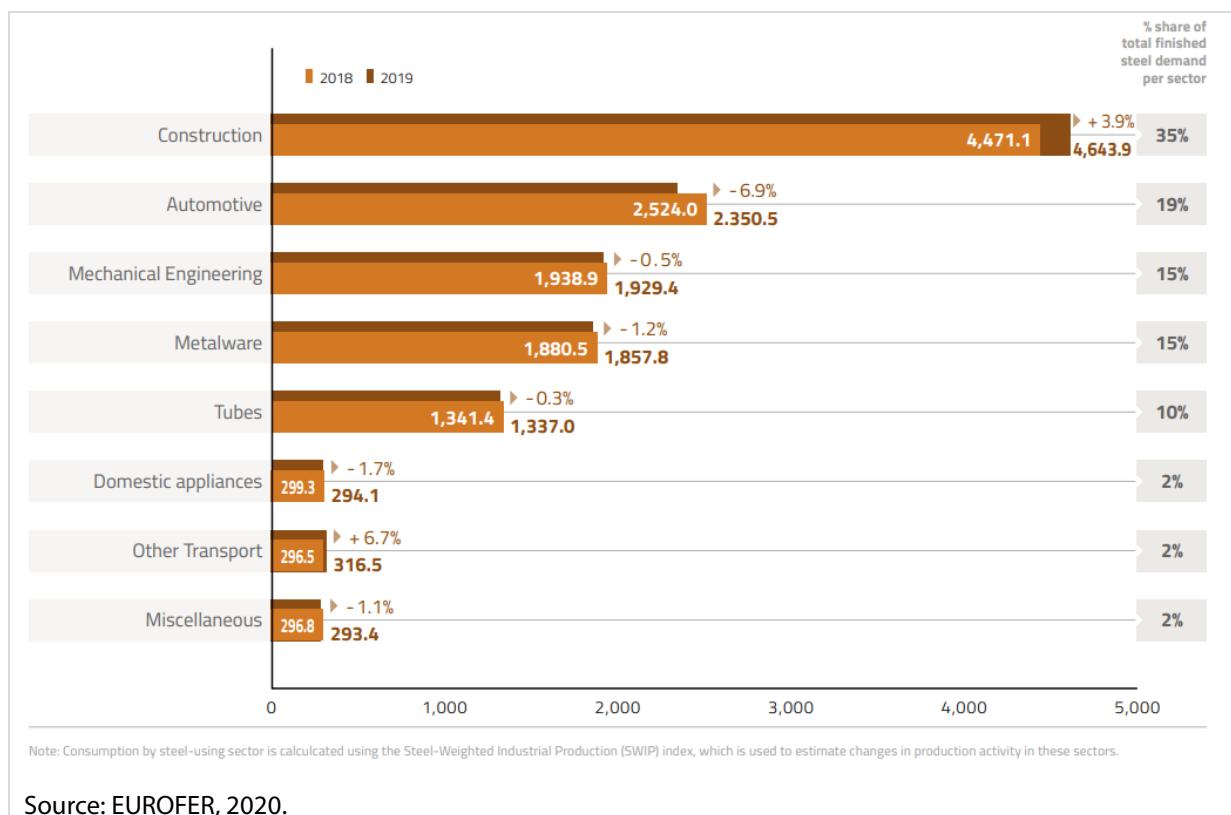
Source: Material Economics, 2019.

Note: Unit: tCO₂/t_{steel}

2.3. Steel products and applications

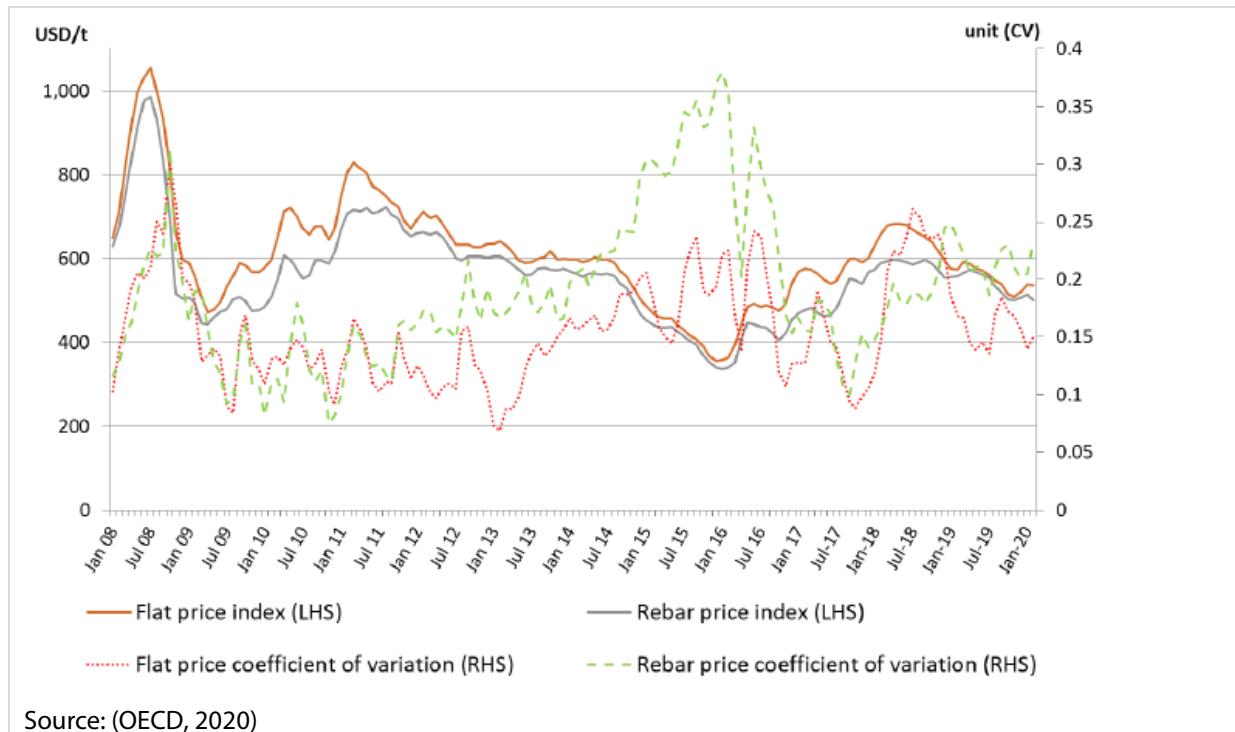
Steel is used in a wide range of sectors, from which the main ones are buildings and infrastructure, mechanical equipment, automotive and metal products. Inherently, semi-finished steel products affect the decarbonisation targets in the above-mentioned sectors as they are part of the supply chain. For instance, car manufacturers Volkswagen and Toyota have committed themselves to fully decarbonise their value chain, including upstream stages. Another recent phenomenon is the rising awareness and commitment of investment firms towards environmental responsibility. Such is the case of the investment firm BlackRock, which is now more oriented toward the sustainability and environmental impact of its business. Therefore, the steel manufacturers have the obligation and the need to keep up with such commitments to remain competitive to maintain their place in the supply chain. In this regard, 14% of the companies in the global steel industry could be at risk if they are not able to reduce their environmental impact, according to a recent analysis of McKinsey & Co. (McKinsey & Company, 2020).

Figure 8. Steel uses and final products



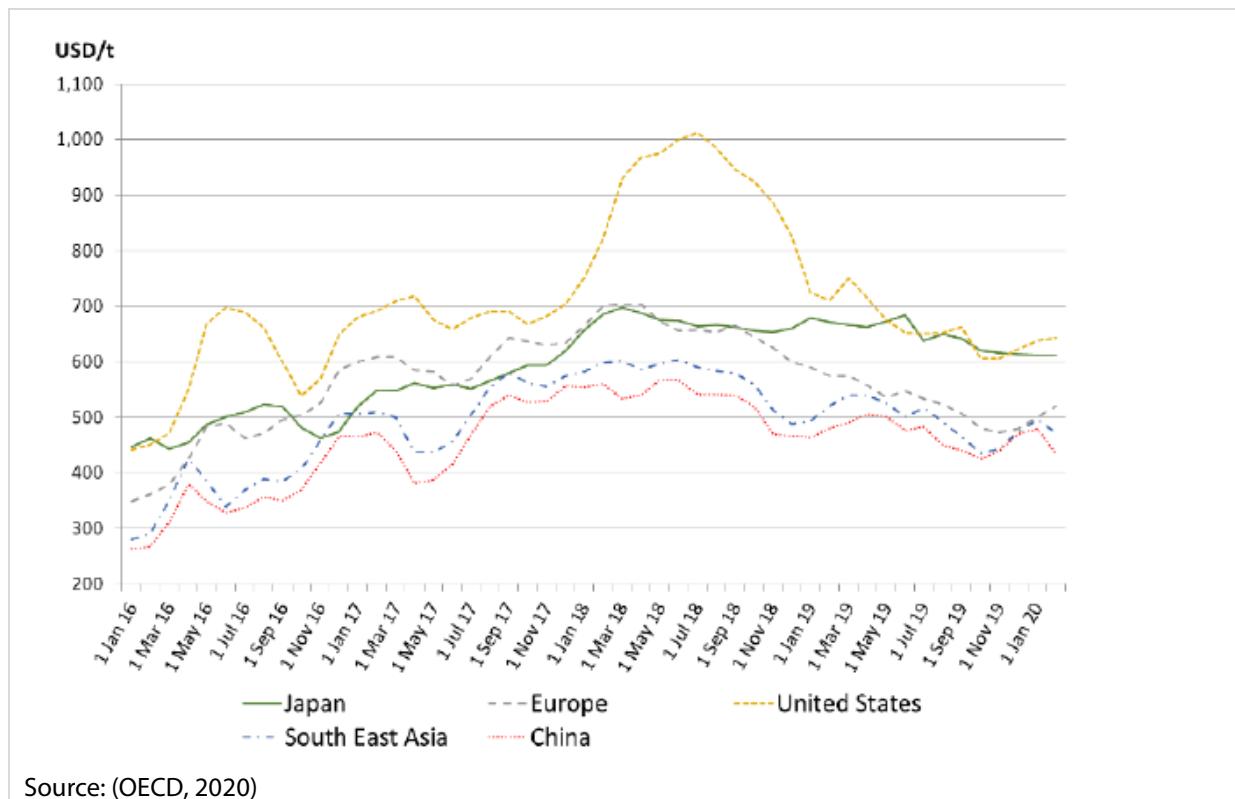
Margins in the steel sector are tight and competition is high, which makes investment decisions challenging. The slowdown due to the COVID-19 pandemic has worsened the situation, resulting in a reduction in demand for steel products in 2020. As a result, the sharp drop in global steel prices, as can be observed in Figure 9, induces a more arduous competition among the different players in the sector, jeopardising the survival or geographical presence of some companies. This situation is more accentuated in Europe, where prices have fallen more dramatically compared with other world regions -nearly 30% since 2018- as can be seen in Figure 10.

Figure 9. Aggregated flat and rebar global steel prices averages



Source: (OECD, 2020)

Figure 10. Steel price for flat products by region



Source: (OECD, 2020)

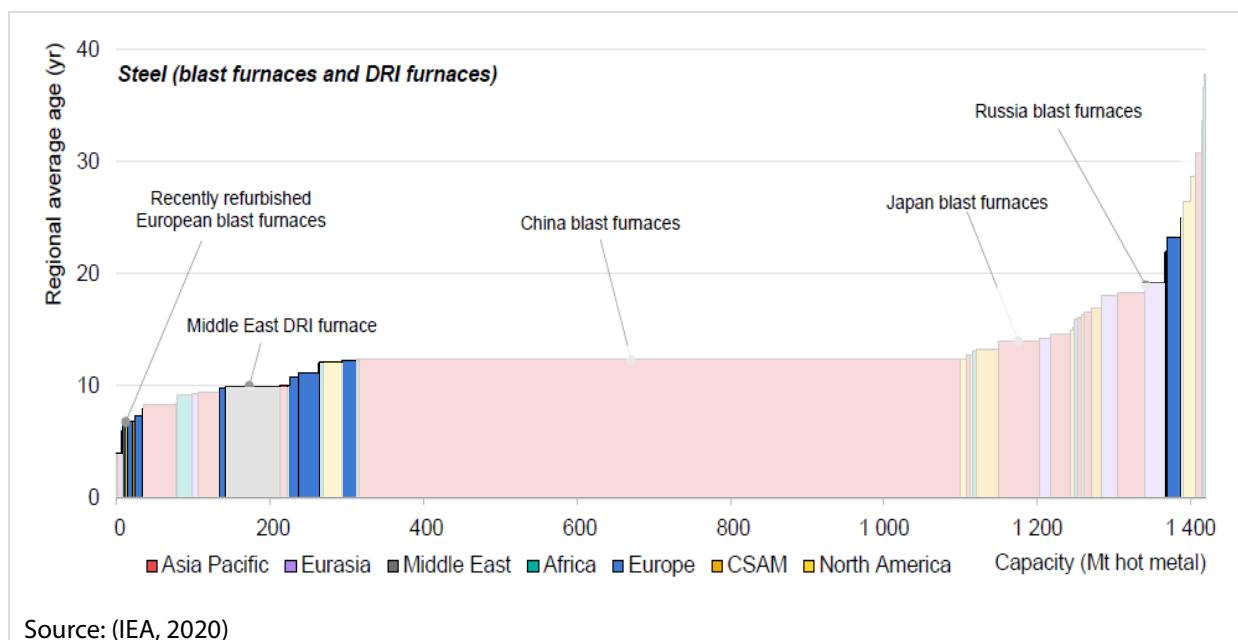
2.4. Decarbonisation paths

The European green deal stresses the need to modernise and decarbonise energy-intensive and hard-to-decarbonise industries such as steel and cement as an essential step toward attaining carbon neutrality by 2050. The solutions designed to eliminate CO₂ emissions in the steel sector can be classified into two main groups: carbon abatement and full decarbonisation. In previous years the emphasis has been on material management and carbon abatement, yet, some emissions will remain considering the limitations of steel scrap availability and opportunities for carbon capture in the steel sector. On the other hand, hydrogen has been regarded as a vital element of the European energy transition and plays a central role in decarbonisation pathways, finding also its position in the steel sector.

Hydrogen can replace the fossil fuels required to reach high temperatures, as well as the carbon used in the reduction of iron ore. To guarantee complete decarbonisation of steel production, the production of hydrogen has to be carbon-free (so-called green hydrogen) and the remaining electricity used in the production process has to originate from renewable energy sources (RES). Another important factor to consider is the hydrogen price as the main enabler of the transition from coal-based production routes. It is expected that the price of green hydrogen (or blue hydrogen) will gradually drop to reach competitive levels in the next three decades.

Finally, it is paramount to not just consider the environmental challenges and commitments that the sector has toward the half of the current century, but to bear in mind the age of the existing assets that are expected to undergo major investment until 2050 (Material Economics, 2019). Existing installations such as blast furnaces have an investment cycle of 10-15 years and coke plants require substantial investments as well. This condition could open a window of opportunities to replace current assets with cleaner and novel technologies while meeting climate targets. While some blast furnaces in Europe are almost 25 years old (see Figure 11), making them fit candidates for technology replacement, others have recently undergone refurbishing works that entailed large investments. Consequently, the decision to shift to a cleaner route is site-specific and will come at different times.

Figure 11. The average age of main assets in the iron and steel sector by region



The following table provides an overview of innovative steel production routes, including the approximate implementation readiness and location of exemplary pilot level projects in Europe.

Table 1. Decarbonisation options for the steel sector

Group	Process/ Tech.	Description	Example	Implem. Readiness	CO2 reduction potential (compared with BF/BOF)	Energy Needs (per ton of steel)
Carbon abatement	BF/BOF + Top gas recovery and recycling	There are two different ways to use the top gas from the blast furnace. Firstly, the gas could be recycled into the blast furnace to reduce the consumption of coke. Secondly, the gas can be used in a Top Recovery Turbine (TRT) to generate electricity.	STEPWISE (Sweden) ArcelorMittal (Belgium)	High	10-20% of CO ₂ emissions	14-16 [GJ/t]
	BF/BOF + Biomass	Partially replace the use of coal and coke with biomass (charcoal, torrefied material, wood pellets) for iron reduction or fuel consumption. It is more feasible in regions with biomass availability such as South America and Russia.	Torero-ArcelorMittal (Belgium) Small tests (Brazil)	High	5-28% of CO ₂ emissions	33-60 [GJ/t]
	BF/BOF + CCU	Deploy carbon capture technologies in the different emissions points of the primary route and valorise the CO ₂ with synergies with the chemical industry, as well as CO ₂ recycling in the BF within the steelmaking process. By hydrogenation ethanol, methanol etc. Can be produced from the CO ₂ emission of the Blast Furnace.	Steelanol (Belgium) Lanzatech (China) FReSMe (Europe) Carbon2Chem (Germany) Carbon4PUR (Europe) IGAR (Belgium)	Medium	up to 65%	18-20 [GJ/t]
	BF/BOF + H ₂ enrichment + CC (optional)	Reduce the use of coal with injections of hydrogen into the Blast Furnace as a reductant agent. This could reduce CO ₂ emissions by 20%. The technology could reduce even more the emissions if coupled with carbon capture technologies.	ThyssenKrupp (Germany)	Medium	up to 72%	17-19 [GJ/t]
	NG-DRI/EAF + CC	Add carbon capture to the emission in the DRI. The carbon concentration in the gas makes it more expensive and technology-wise more challenging to reach a high capture level.	Al Reyadah (Abu Dhabi)	Medium/ High	up to 80%	15-17 [GJ/t]
	NG-DRI/EAF + H ₂ injections + CC (optional)	In the NG-DRI/EAF, H ₂ is obtained from natural gas, this could be replaced up to one third by green hydrogen directly injected into the shaft, reducing, thus, its CO ₂ emissions.	MIDREX H ₂	Medium	up to 80%, plus H ₂ mix	16-18 [GJ/t]
	Smelting reduction + CCUS	It is a combination of direct reduction and smelting process to produce molten pig iron directly using coal instead of coke. The plant is intended to operate with CCUS to increase its environmental impact.	Hisarna - TATA steel	Medium	by 20%, and up to 80% with CC	15-17 [GJ/t]

Group	Process/ Tech.	Description	Example	Implem. Readiness	CO2 reduction potential (compared with BF/BOF)	Energy Needs (per ton of steel)
Full decarbonisation	H2-DRI/EAF	Hydrogen is used as the only reductant gas in the shaft to produce sponge iron. If the electricity to produce H2 and in the EAF is carbon-free, the steel production has no CO ₂ emissions.	HYBRIT (Sweden) Voestalpine (Austria) ThyssenKrupp (Germany)	High	Up to 100%	17-19 [GJ/t]
	Smelting reduction: H2 plasma	In the hydrogen plasma smelting reduction, iron ore is reduced by hydrogen in the plasma state in a plasma arc reactor.	SuSteel (Austria) University of Utha (USA)	Medium	Up to 100%	-
	Iron ore electrolysis	Iron ore is dissolved in a solvent at high temperatures, where electric current negatively charges oxygen ions and separating O ₂ from the iron ore. There are two main routes: Molten Oxide Electrolysis (MOE) and Electrowinning Process (ULCOWIN)	Boston Metal (USA) Siderwin (Europe)	Medium	Up to 100%	13-15 [GJ/t]

Source: VITO based on (IEA, 2020), (IEA, 2019), and own calculation and database.

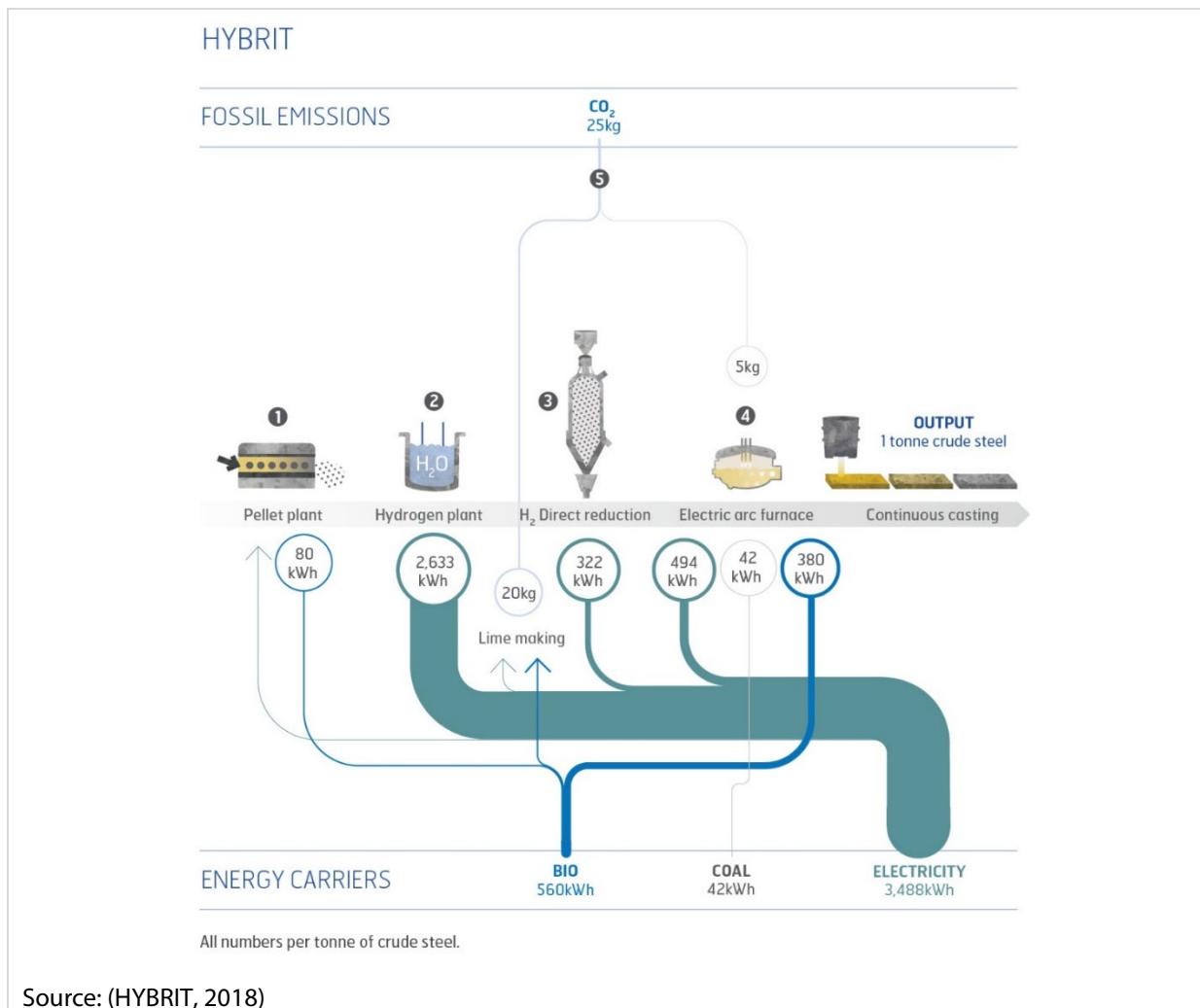
2.4.1. Hydrogen-based steel production

A small quantity of steel is made today using what is called the 'direct reduction' process, approximately 7% of the 1 402 Mt of primary steel production in 2018 (IEA, 2019). This is a mature technology, which could also be operated solely on hydrogen. The base principle of the hydrogen reduction route (H-DRI) is the use of hydrogen as a reductant agent to obtain sponge iron (direct reduced iron) instead of the current use of a mix of hydrogen and carbon in the BF. Only water is obtained as a by-product of the hydrogen-based process. The reaction takes place in a shaft furnace at an operating temperature of around 800°C. The operating temperature could be reached by employing electrification and the use of residual heat within the same process. Afterwards, sponge iron is tuned into crude steel in an EAF, where a carbon source is still needed to obtain steel with a carbon content of less than 0.4%. To fully decarbonise the entire production route, the carbon source for the pellet production plant, the lime production plant, and the EAF have to be considered. Options would be the use of biomass or bio-coal. Additionally, the electricity consumed in the process needs to originate come from renewable sources.

In Europe, several projects are being tested and pilot plants initiated, which are backed by iron and steel producers such as SSAB, LKAB, Voestalpine, ThyssenKrupp, and Salzgitter. These companies expect the technology to reach commercialisation at large capacities by 2035 (Material Economics, 2019). The first experiments in large scale direct reduction using pure hydrogen are now being carried out at the SSAB steel facilities in Sweden under the HYBRIT⁴ project. These pilots will provide more precise data on the amount of hydrogen needed.

⁴ <https://www.hybritdevelopment.com/>

Figure 12. Hydrogen direct iron reduction process in the HYBRIT project



Source: (HYBRIT, 2018)

It is estimated that the H-DRI steel production theoretically requires 51-57 kgH₂/t_{steel}⁵, assuming 100% reaction efficiency in the shaft. However, this is not always the case and the consumption of hydrogen could increase accordingly to reach values near 65-80 kgH₂/t_{steel}, depending on operating conditions⁶. An additional factor affecting the hydrogen requirements is the scrap-to-iron ratio in the EAF, which reduces the need for sponge iron per ton of steel. If it is assumed to use 70 kgH₂/t_{steel} and zero scrap in the EAF, 3.2 MWh of clean electricity are required to produce one ton of primary steel. To cover the total European production of primary flat steel in 2019 - 94 Mt according to EUROFER - a total of 296 TWh of clean electricity would be required to power 55 GW of electrolyser⁷. To put these numbers into perspective; the total electricity production of EU27 in 2019 was 2 724 TWh⁸. Germany produced 176 TWh of green electricity in 2020 (Energy Charts, 2021). This means that around 10% of the annual produced electricity in the EU alone would be needed to supply the steel industry. Additionally, the required capacity of electrolyser exceeds the 40 GW envisioned in the 2x40 FW initiative. See also Figure 13 for a simplified overview of the assumptions in this paragraph.

⁵ Based on LHV and 74% efficiency of electrolyzer for the HYBRIT project.⁶ Reaction efficiency assumed to be 65-80%.⁷ Full load= 5000 hours per year.⁸ Data from EUROSTAT report: <https://ec.europa.eu/eurostat/statistics-explained/pdfscache/9990.pdf>

Figure 13. High-level hydrogen-based steelmaking infographic

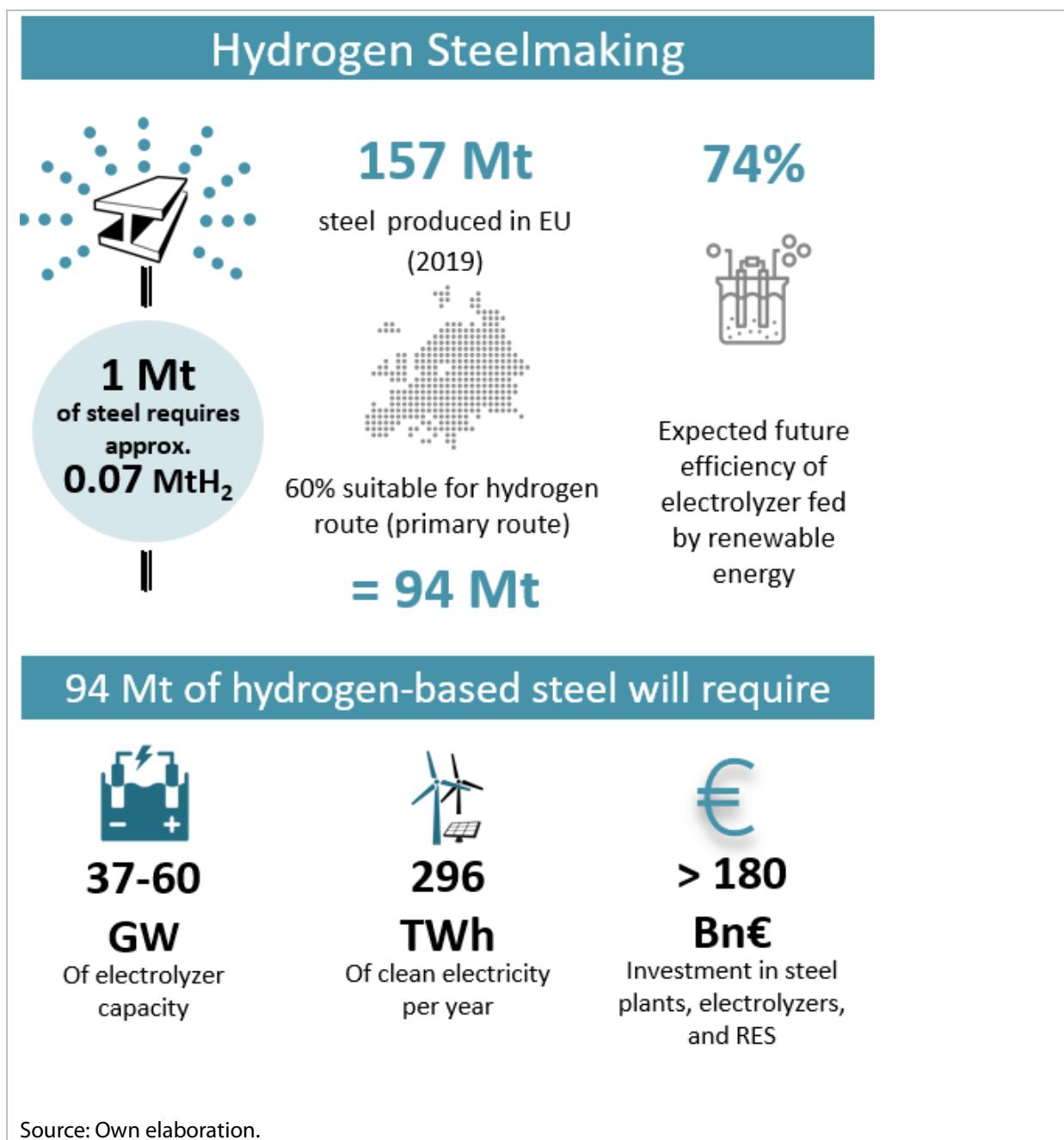


Table 2. Hydrogen-based steel production projects in Europe

<i>H₂-DRI projects in Europe</i>	
HYBRIT⁹: Hydrogen Breakthrough Ironmaking Technology is a joint venture of SSAB, LKAB, and Vattenfall, launched in 2016 in Sweden, with the aim to have a fossil-free steel production solution by 2035. This will help SSAB to be practically carbon-free by 2045.	LKAB¹²: The mining group plans to integrate downstream and initiate trading sponge iron produce entirely using H ₂ from renewable energy sources. In other words, it will install hydrogen shafts (H-DRI), without the EAF step.
ArcelorMittal¹⁰: In 2019, ArcelorMittal started collaborating with Midrex to build a production plant able to annually produce 0.1 Mt _{steel} using only H ₂ as a reductant agent in Hamburg, Germany. It will initially start production using grey hydrogen and be ready for when green hydrogen supply is reliable and affordable.	Voestalpine¹³: The production facility in Linz, Austria, in association with VERBUND, Siemens, Austrian Power Grid, K1-MET, and TNO are under development. With 6 MW of electrolyser capacity, the project expects to reduce by 30% the emissions of Voestalpine by 2035, with the final goal of reducing the emission by over 80% by 2050.
Thyssenkrupp¹¹: In partnership with REW, the steel producer expects to convert its current BF/BOF production into H-DRI by 2050. Starting with the facilities in Duisburg (2% of Germany's CO ₂ emissions) in 2025, one of the main challenges is the need for a pipeline to transport H ₂ from Lingen to the plant. If H ₂ is not available in the quantities needed, the plant will start running on natural gas.	Salzgitter¹⁴: With the project SALCOS, the company expects to develop and demonstrate the techno-economic feasibility of hydrogen-based steel production. The project is divided into several stages: demonstration of MW scale electrolyser, wind power production onsite, pipe for H ₂ transport and storage, and final profitability for steel production.
	Liberty Steel Group¹⁵: Construction of a DRI/EAF plant to produce 2 Mt _{steel} . It will be designed to phase into H ₂ from natural gas (grey H ₂), reaching carbon neutrality by 2030.

Source: own elaboration.

The supply of H₂ to the hydrogen shaft could be done by installing an electrolyser within the facilities of the steel plant, in which case the storage of H₂ should be considered to keep production rates stable. The second alternative is the use of a pipeline to link the hydrogen production sites with the consumption centres. Both methods are challenging and the prevalence of one over the other depends strongly on the location of the steel plant and the access to cheap and renewable energy.

⁹ <https://www.hybritdevelopment.com/>

¹⁰ <https://corporate.arcelormittal.com/media/case-studies/hydrogen-based-steelmaking-to-begin-in-hamburg>

¹¹ <https://www.thyssenkrupp.com/en/newsroom/press-releases>

¹² <https://www.lkab.com/en/news-room/press-releases>

¹³ <https://www.voestalpine.com/group/en/media/press-releases>

¹⁴ <https://salcos.salzgitter-ag.com/en/>

¹⁵ <https://libertysteelgroup.com/news>

In a transitioning phase, some argue that hydrogen could be blended into the natural gas grid (for more details see chapter 5.4). However, in the case of H-DRI, such an alternative entails further challenges and discussion. For instance, to fully reach decarbonisation of crude steel production, sites would have to invest not only in the direct reduction shaft and the EAF but also in carbon capture and transport facilities. This high overnight investment together with high natural gas prices is the reason why DRI plants are mainly located where natural gas is cheap (e.g.: The Middle East and Russia).

Moving forward

Continue political and social momentum for decarbonisation (carbon dioxide pricing, hydrogen economy boosting plans and subsidies) to accelerate knowledge exchange, innovation and technological shift.

Joint effort between governments, regulators and industry to alleviate overnight required investments and increase market stability.

To reach long-term environmental goals, decisions made today must follow a **clear decarbonisation road map** since industrial sites have long lifetimes and investment cycles.

Steel decarbonisation timeline should be aligned and back with national and industry roadmaps for RES deployment, infrastructure development, supply and decarbonisation plans in other sectors.

Supply and infrastructure investment could pave the way for industrial hydrogen demand.

Financial support to mitigate investment risk due to supply risk and market uncertainty, especially in sectors with tight margins.

Harmonization and common standards covering hydrogen purity, hydrogen-natural-gas blending and market regulation.

Another barrier is the regulatory framework needed to guarantee the same mixture (hydrogen share) in all the European natural gas grid (see chapter 5.4), as well as determine the price of the hydrogen injected into the pipelines and the remuneration rules for natural gas and hydrogen suppliers. To illustrate this, consider that hydrogen density is approximately eight times lower than the one of natural gas¹⁶ and the hydrogen content of natural gas is 25%, then, the quantity of hydrogen and natural gas mixture to be delivered would decrease, although not in a linear proportion. For instance, with a 5% of hydrogen mixture the mass delivered would decrease by 13%, while with a 20% hydrogen mixture the decrease would be 37%. These changing conditions could impose operating and regulatory challenges for the natural gas-hydrogen blending case.

While the transport of electricity entails fewer energy losses than the pipeline option, the variability of renewables plus the normally constant operation of the steel plants could further congest the power grid. This happens especially in highly concentrated and sometimes congested industrial hubs. Thus, for

the onsite electrolyser case, an ad-hoc storage unit should be included in order to deal with green electricity fluctuations and other electricity supply restrictions that might occur. On the other hand, in the case of a pipeline, such infrastructure needs to be developed and tested to assess its real capacity and reliability. However, and in contrast to the traditional primary route, the DRI system is flexible in terms of production and electricity demand. This feature could help with grid flexibility employing hydrogen and hot-briquetted iron storage, as well as the reduction of the share of scrap used to cope to some extent with shortages of H₂.

2.4.2. Alternatives pathways to decarbonise steel production

Besides the hydrogen route to reach full decarbonisation in the steel industry, some other technologies and projects reduce the carbon intensity partially (see Table 1). Although most of these alternatives are far to reach full decarbonisation some might turn out to be advantageous and favourable in the transition phase. Beyond the technology path to replace natural gas with hydrogen without major changes to the shaft (DRI), other alternatives that require lower investments seem to be appealing in the short term. As mentioned above, the assets of the steel industry require

¹⁶ Assuming natural gas density to be the same as methane density.

significant investments, especially considering the current age of the assets. This could suggest that steel producers will initially focus on incremental solutions to reduce carbon emissions (e.g.: top gas recovery, carbon capture, H₂ injections) before moving to more disruptive process changes such as hydrogen direct reduction or iron electrolysis. This approach may extend the life of current assets while reaching interim milestones to carbon neutrality by 2050. However, it is important to note the limitation of the maximal decarbonisation potential that alternatives such as BF top gas recovery or BF-CCUS have (see Table 1).

When considering a carbon capture and storage or utilisation approach, it is critical to consider that currently there is no market for the vast amount of CO₂ that will originate from the steel sector in the case of BF-CCUS or NG-DRI-CCUS. Therefore, the establishment of synergies with the chemical sector should be developed alongside the progress of this decarbonisation pathway. On the other hand, carbon storage still needs to overcome public acceptance and scale-up. It is estimated that at present there are 26 CCS plants in operation with a capacity of 39 MtCO₂ per year – equivalent to approximately 0.1% of global emissions from fossil fuels (Friends of the Earth Scotland and Global Witness, 2020). One of Europe's most advanced carbon capture and storage projects, the Northern Lights project in Norway, is envisioned to have an annual storage capacity of 1.5 MtCO₂¹⁷, which would be sufficient to store only approximately 1% of the current iron and steel industry emissions from Europe (EU28)¹⁸.

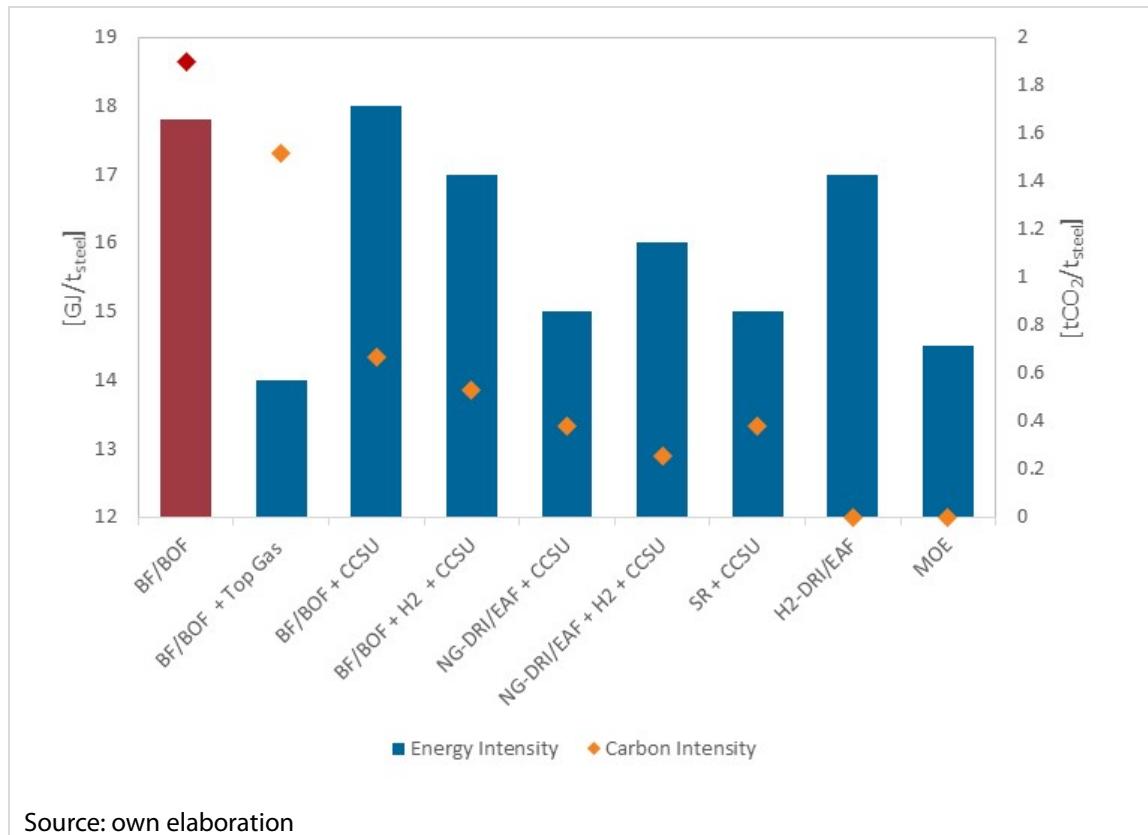
Finally, the use of turquoise hydrogen¹⁹, as well as the direct use of ammonia in the direct reduction of iron ore (DRI), are emerging alternatives that could solve some barriers of other similar routes. In the case of turquoise H₂, the storage of CO₂ could be partially solved since the use of carbon black²⁰ is more common nowadays as well as its transport and storage. Moreover, the direct use of ammonia to reduce iron could solve the reconversion losses in H₂ shipping using ammonia as a carrier, since ammonia is much easier to handle compared to H₂ in gaseous or liquid format. The iron electrolysis route has the advantage that it does not involve electrolysis of water or the hydrogen transport challenges. Still, it is a technology that is not close to maturity and involves very high investments. However, it could play a role in the long term to compete with low carbon H₂.

¹⁷ It corresponds to the capacity indicated by Equinor in its website.

¹⁸ Data from Eurostat: Greenhouse gas emissions by source sector. Total emissions = fuel emissions + process emissions.

¹⁹ Turquoise hydrogen is a by-product of methane (natural gas) pyrolysis, which splits methane into hydrogen gas and solid carbon, see Chapter 0.

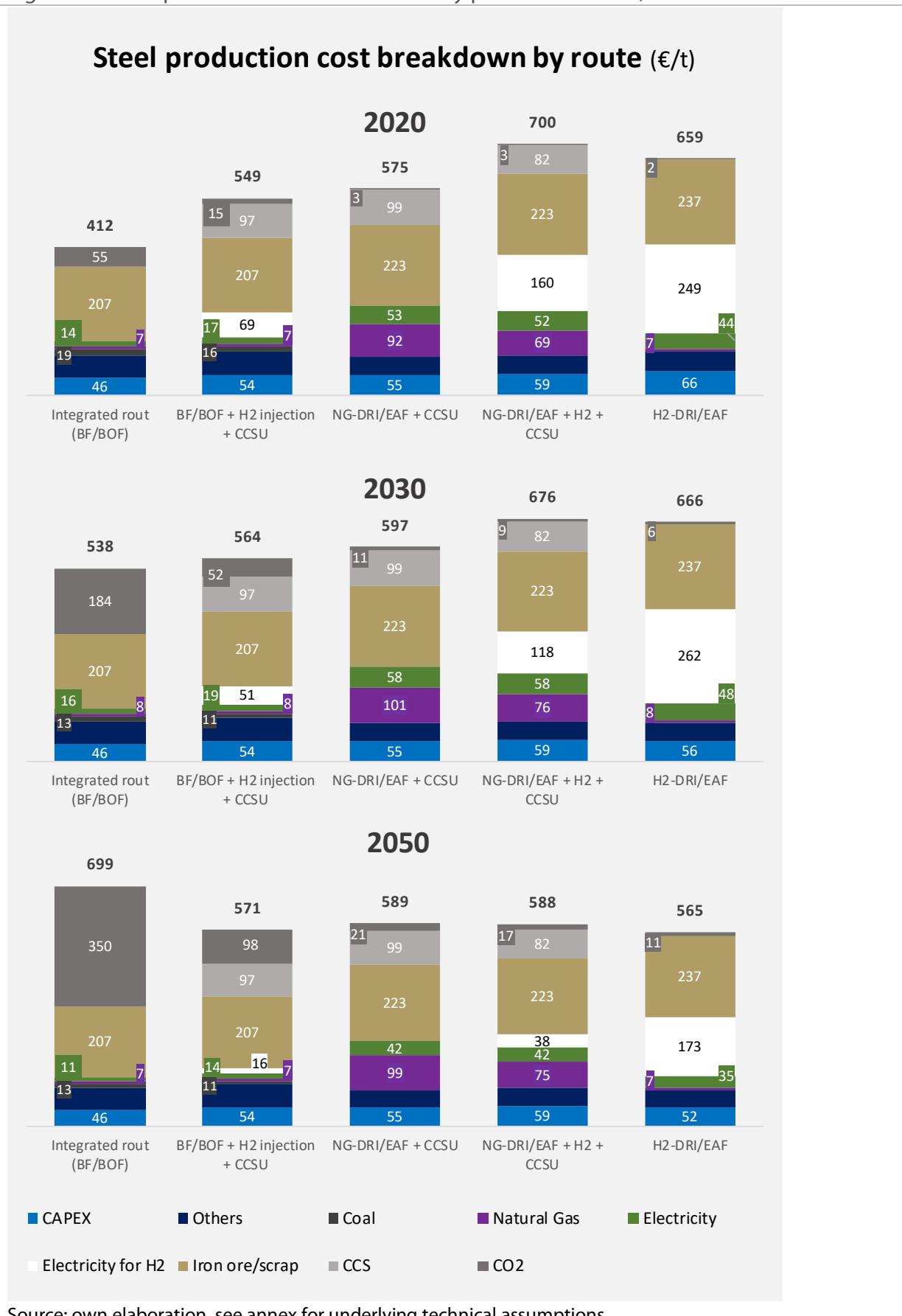
²⁰ Carbon black is a by-product of natural gas pyrolysis. It should not be confused with black carbon, an unwanted pollutant from incomplete combustion.

Figure 14. Energy intensity and CO₂ emissions by steel production route

Source: own elaboration

Reducing the carbon intensity of steel production will imply some costs as well as policies enabling novel production routes to reach cost competitiveness in the long run. The average production cost of the integrated route (BF/BOF) remains the cheapest one up to 2030. However, the gap with other routes shrinks as electricity prices decrease and CO₂ emissions prices increase. By 2050, the integrated route could lose its competitive status mainly due to the increase of the CO₂ emissions price. The production cost of the rest of the routes will come closer to each other, where hydrogen DRI becomes the most economical route under certain conditions. Forecasting the steel production cost comes with high uncertainty due to the volatility and expected change of several of the parameters involved in the production (e.g.: iron ore price, electricity price, electrolyser CAPEX, CO₂ emission price, etc.). Thus, under certain assumptions (see Techno-economic assumption), Figure 15 shows the weight of the different parameters in the final product price of steel, including the sinter, lime, coke plants and the finishing step. By 2030, the cleaner routes will have an environmental premium of 5-24% and an abatement cost of €73-€166 per ton of CO₂, when compared with the integrated route (BF/BOF).

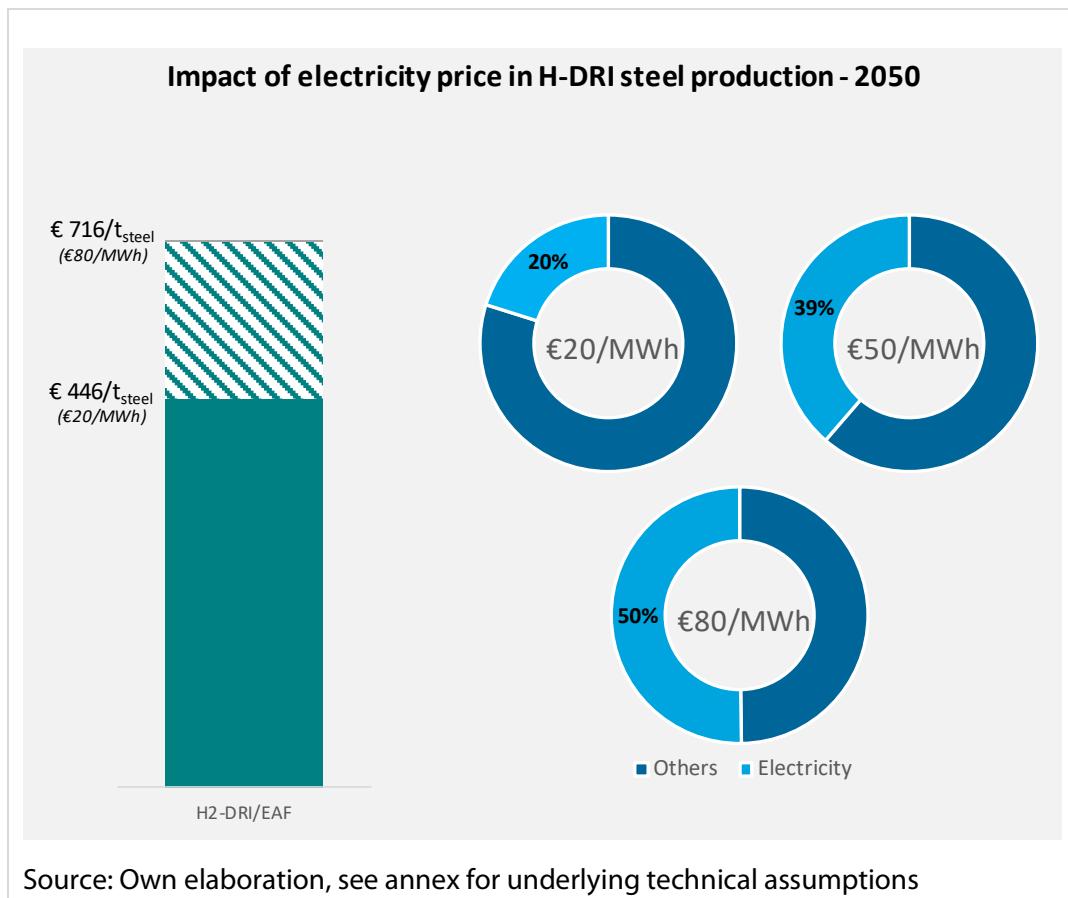
Figure 15. Steel production cost breakdown by production route, 2020 / 2030 / 2050



Source: own elaboration, see annex for underlying technical assumptions

Since the hydrogen-direct-reduction alternative is highly sensitive to electricity prices -or hydrogen price centrally produced- the location within Europe of the steelmaking sites and access to cheap electricity could be advantageous. Electricity prices in 2050 involve great uncertainty, especially when high penetration of renewables is considered. IEA estimates a variable renewable price of €43/MWh in the long term in Europe (IEA, 2019), however, lower prices are expected to be attained in southern Europe (Spain, Portugal, and Italy). Figure 16 shows the impact of electricity prices ranging between €20/MWh to €80/MWh on the steel production cost for the H-DRI route. In the two extremes, the electricity share of the production cost increases from 20% in the case of cheap electricity up to 50% when electricity prices are high.

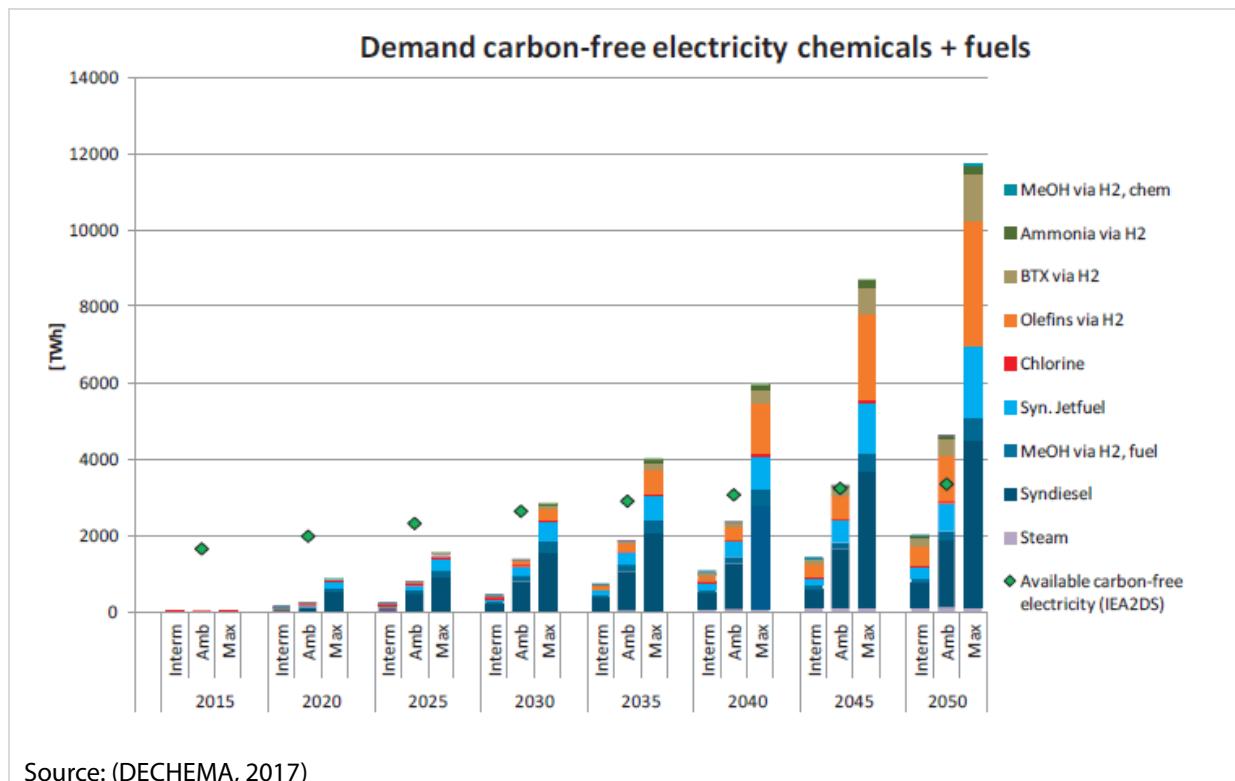
Figure 16. Hydrogen route steel production price sensitivity to electricity prices in 2050



Source: Own elaboration, see annex for underlying technical assumptions

The steel sector will have to compete with other sectors for access to low-carbon hydrogen to reach the environmental targets set for those sectors. Such is the case of the chemical sector, which is well-positioned to use green or blue hydrogen when available at competitive prices. The chemical industry uses hydrogen in the production of several platform molecules or end products such as methanol, ammonia and olefins, which are currently produced chiefly using natural gas. DECHEMA estimated in 2017 that the use of hydrogen produced from low-carbon electricity will be part of the decarbonisation path of the chemical industry, utilizing 500 - 1 400 TWh in 2030 and 2 000 – 4 500 TWh in 2050 (DECHEMA, 2017).

Figure 17. Carbon-free electricity demand of hydrogen-based routes



Source: (DECHEMA, 2017)

3. Case Study 'A Long-term vision on steel production'

Takeaways

A global long-term steel study by Vito and KTH (Stockholm) evaluated the evolution of the global steel sector taking into account:

- 13 world regions, modelling for each region.
- The projected demand for long and flat steel products;
- The projected availability of steel scrap re-entering the production cycle;
- The projected trade among the world regions to balance supply and demand.

The main insights of study show that ...

- Global steel demand will increase and plateau by 2070;
- Majority of production increase will mainly be observed in flat steel production (87%) and less so in long steel (30%);
- The availability of steel scrap will increase by 167 % and play an important role in decarbonizing the long steel production;
- GHG policies (such as unilateral CO₂ taxes in one region) can heavily impact the location of production facilities;
- Trade of scrap and finished products among regions balance the demand and supply globally making well developed regions (e.g. Europe) net-exporters while maintaining their existing production facilities.

Vito and KTH Royal Institute of Technology (Stockholm) conducted a study (Xylia, Silveira, Duerinck, & Meinke-Hubeny, 2018) in collaboration with Arcelor Mittal, the largest steel production company in the world in 2016. The likely evolution of steel production, recycling, demand and trade among 13 defined world regions from today till the year 2070 are evaluated.

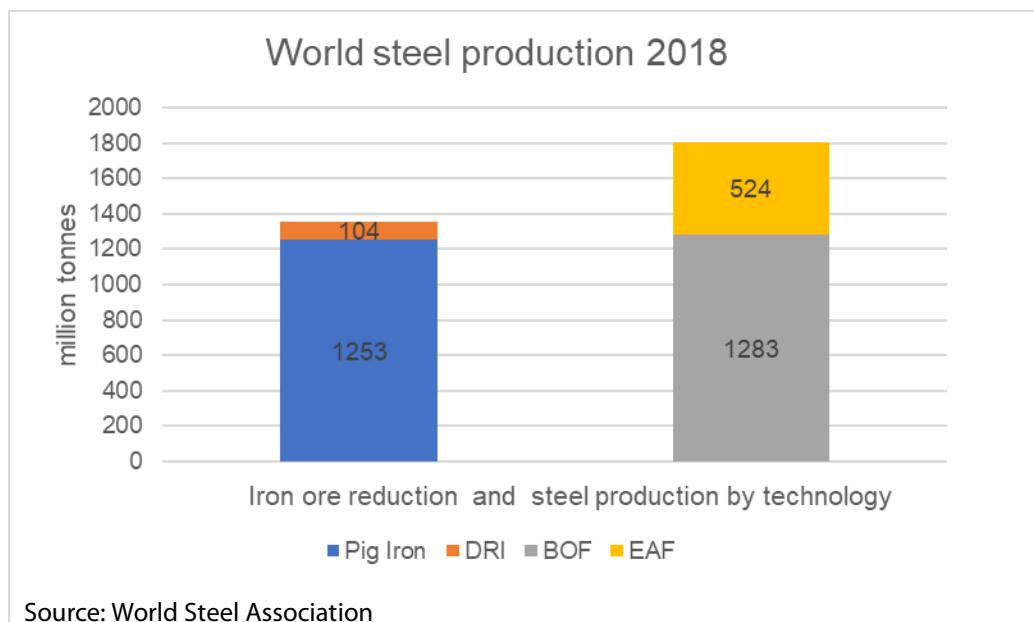
For this study, a Global Steel Production and Scrap Availability Model has been developed and applied. The Global Steel Production and Scrap Availability Model is a peer-reviewed model that has been created by VITO in cooperation with KTH. In this section, this model will be introduced, and the main findings of the study presented.

3.1. Base assumptions - Steel production in a nutshell

All steel in the world originates from iron ore either directly, or indirectly through recycled scrap molecules consisting of iron and oxygen atoms. The production of steel can be represented in a simplified way as a two-stage process. In the first step, the oxygen is removed from iron ore molecules. This is done by a chemical reaction in the presence of a reducing agent. This is an energy-intensive process at elevated temperatures and depending on the reducing agent it is also a CO₂-intensive process. The second step is to produce liquid steel, suitable for further processing. In this process, impurities are removed, and the material is melted if required. Figure 18 presents the quantities processed by different technologies for the two stages.

Note: The product categories, data, and graphs in this chapter reflect the assumption chosen in the aforementioned study and the underlying Global Steel Production and Scrap Availability Model and might show slight deviations from values in other chapters of this report.

Figure 18. World steel production by technology



3.1.1. Steel recycling

Steel recycling is a cost-competitive option for decarbonising the steel sector. If the electricity supplied to the Electric Arc Furnace (EAF) is carbon-free, then this steel is almost carbon-free. Steel can be recycled endlessly, and recycling rates are very high. Between 2000 and 2018 scrap use increased by 136%. Steel scrap accounts now for 23% of global steel production and scrap availability is expected to increase further. Consequently, in any decarbonisation scenario, steel recycling will play a major role.

The availability of steel scrap is considered in the steel production scenarios that will be discussed further on. However, for a proper understanding it is useful to take into account different type of scrap quality, which are also introduced in the applied model:

- Own scrap refers to material losses in the steel company itself, mainly in the finishing section. This scrap is of the highest quality and recycled internally.
- Prompt scrap is lost material in the manufacturing industry and also of very high quality. This is mainly recycled to the steel company that produced the steel within a short delay.
- Obsolete scrap is scrap released at the end of the life of products and is collected by scrap dealers. The delay between production and recycling depends on the type of application. E.g. beverage cans have a short lifetime (1-2 years), transport equipment such as cars have a longer lifetime (6-20 years), and in construction, lifetimes can sometimes exceed 100 years, e.g. in buildings or bridges.

Whereas availability for the first two categories can be considered as being related to steel production itself, this is no longer the case for obsolete scrap. Availability of obsolete scrap depends on a long history of steel use, which is closely tied to the economic development of the respective world region. With respect to the geographic availability of scrap, there is also a layer of complexity since for certain steel applications, the demolishing can take place in another region than the

production of usage. A further aspect to consider is the composition of the scrap in terms of impurities. For own and prompt scrap the precise composition is known, facilitating the recycling for production of similar steel qualities. Obsolete scrap is a mixture of various sources and the composition (level and type of impurities) is not known and not consistent.

3.1.2. Steel products: Flat steel and long steel

The World Steel Organisation (WSO) produces detailed statistics per country. In these statistics, a differentiation is made between flat products and long products. Flat products have major applications in car manufacturing, household appliances, radiators and many others. Long products, on the contrary, have major applications in infrastructural works (bridges, buildings, concrete reinforcing, railways, etc.). Although both steel types can be produced by different production routes, the distinction is relevant in this context as scrap quality requirements for flat products are higher compared to long products.

3.2. The global steel production and scrap availability model

The global steel production model is a techno-economic 13 region model that has been designed to develop steel production scenarios with a long-term horizon (up to 2100). Starting from demographic projections, based on the UN statistical department work and macro-economic growth assumptions, the model generates demand for flat- and long steel products and determines optimal production pathways, considering the historical background. The 13 regions are linked by trade variables for flat- and long steel products and for high quality and low-quality scrap.

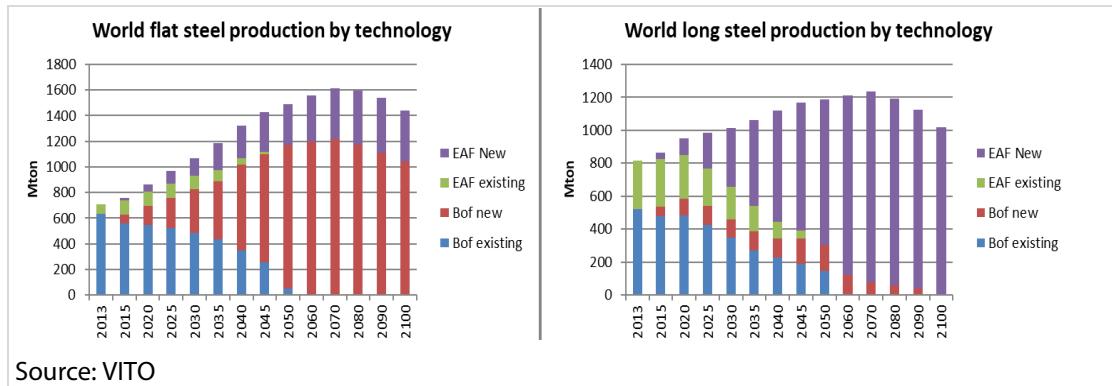
Optimal production pathways are calculated by the model from a cost minimisation perspective. The model output provides the least-cost solution to supply the world with the required quantities of flat and long steel products over the full model horizon, considering feedstock, CAPEX, and transport cost for all possible options.

Historical background includes the long-term history of steel appliances that become available as scrap, the lifetime structure of existing steel production plants. The history of steel consumption in developed countries has also been used as a reference to estimate the steel consumption in developing countries.

3.3. Scenario results

Global and European production scenario results from the Global Steel Production model are presented in Figure 19 and Figure 20.

Figure 19. Global steel production scenarios



Source: VITO

To satisfy increasing demand, the model results show a global flat steel production increase of 87% and production of long products of 30% between 2020 and 2070. However, in the same period, the availability of scrap is expected to increase by 167%, allowing for a higher share of EAF production. The production of virgin material tends to stabilise between 2020 and 2070. As EAF production is far less energy and CO₂ intensive, these scenarios don't demonstrate a dramatic increase in CO₂ emissions but rather a stabilisation.

A key issue in these scenarios is the allocation of global scrap available. Scrap availability is a function of historical steel use and tends to be much higher in well-developed countries. As steel recycling is the most cost-efficient way for decarbonising the steel sector, one would expect that developed countries have more cost-efficient options to decarbonise their respective sector, because of the high availability of scrap material. However, when looking at recent steel trade data we observe that well-developed regions like Europe and North America are net exporters of scrap.

As global warming is related to global GHG emissions and not to their specific location, a global approach is used to allocate available scrap among the 13 regions in the Global Steel Production and Scrap Availability Model, i.e. scrap is considered as a tradable good and the allocation is purely based on economic considerations, namely to find globally the cheapest solution to satisfy the steel demand for flat and long products in each region of the world. The results of this approach are illustrated in Figure 21. In a global cost optimising setting Africa, India and other Asia (Asia excluding China, India, South Korea, and Japan) will become major scrap importers by 2050 and Europe (30 countries – including UK, Switzerland, and Norway) becomes the second-largest exporter after China, exporting almost 55 Mton of scrap (compared to 275 Mton for China).

European scrap exports are also considered in the European Steel Production scenarios in Figure 20. By 2050, long products are completely based on the use of scrap in EAF, but for flat products, EAF takes only a small fraction and the major part (93 Mton) is still virgin production from iron ore (represented as BOF new).

Figure 20. European steel production scenarios

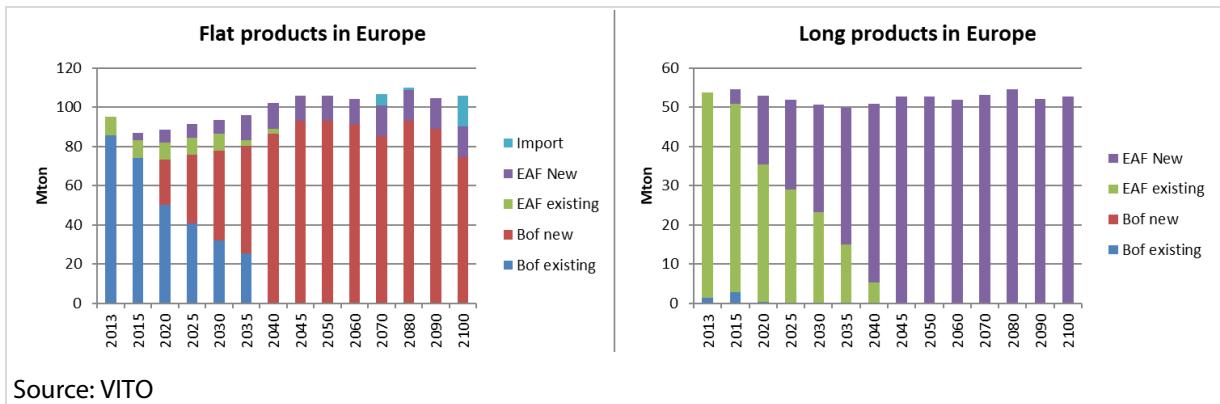
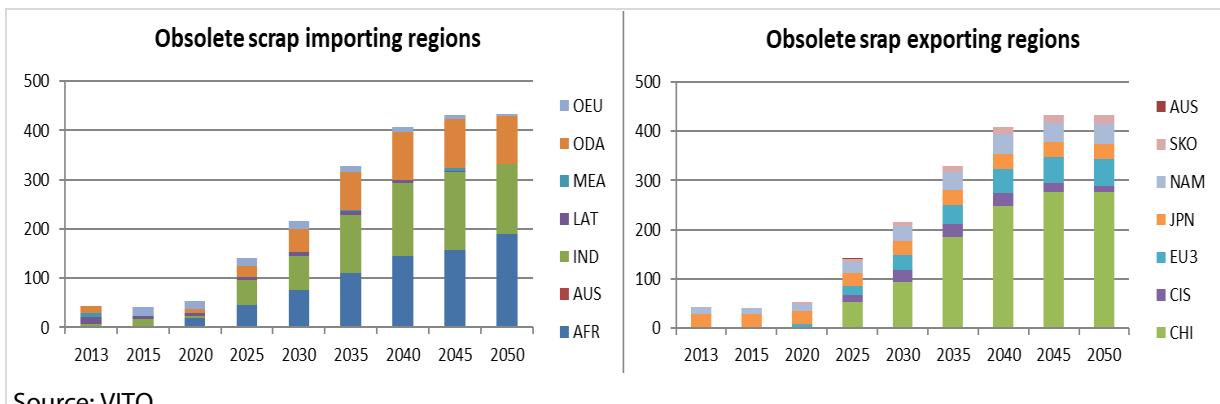
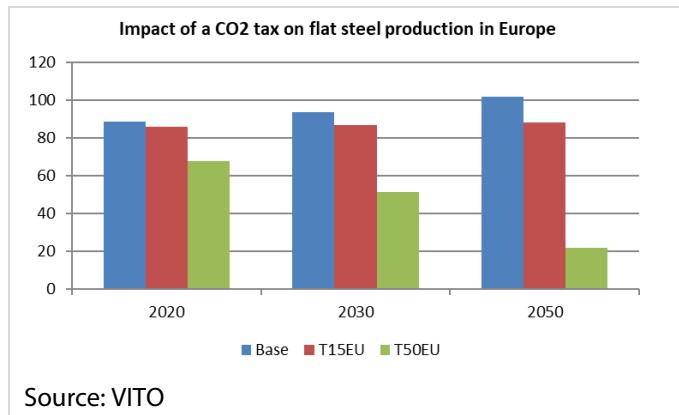


Figure 21. Trade of obsolete scrap in the global steel production scenario



The global steel production model has also been used to investigate the potential impact of an isolated European Climate Policy in the absence of any special external border policies, i.e. import restrictions/border taxation for embedded CO₂ emissions of imported steel. For this exercise, we simply applied a CO₂ price of respectively €15 and €50 on CO₂ emissions of European steel producers. This has mainly an impact on flat steel production and less on long production as it will be based on the use of scrap. For €15/ton CO₂ the impact is rather limited, but for €50 we see that European flat steel production will be very sensitive to re-locate to other regions in the world with a CO₂ price.

Figure 22. Potential impact of a European Climate Policy



Note: Base = Model scenario without CO₂ price, T15EU & T50EU = Scenarios with a respective 15 / 50 Euro per ton CO₂ price in the Europe region only.

4. Production and supply of hydrogen

Takeaways

- If the primary steel produced in Europe is expected to be produced solely by H-DRI route, it is necessary to produce 6-8 MtH₂ (green/blue hydrogen) by 2050. This is almost all the green hydrogen expected in the EU Hydrogen Strategy in 2030 (10 MtH₂), and more than the hydrogen allocated as feedstock in the Hydrogen Roadmap Europe-FCH-JU (10 MtH₂).
- Besides water electrolysis (Green H₂), natural gas based pyrolysis (Turquoise H₂) and iron ore electrolysis can offer an almost carbon free alternative to BF/BOF.
- Delivering low-carbon hydrogen to steel production sites depends on the development of a reliable and suited infrastructure (pipelines, compression units, storage, power grid).

Hydrogen is an odourless, invisible gas and one of the most abundant elements on earth. However, it is rarely found in its pure form (H₂) and more commonly as a compound such as in water (H₂O) or methane (CH₄). Therefore, it must be obtained by separating processes such as Steam Methane Reforming (SMR), water electrolysis, Auto Thermal Reforming (ATR), and pyrolysis. Since hydrogen is not an energy source itself but rather an energy carrier, its production requires a certain amount of energy to break the covalent bonds²¹ that keep the hydrogen molecules bonded to other elements.

4.1. Production of hydrogen

The source of hydrogen as well as the technology used to produce it determine the carbon emissions associated and, therefore, the type of hydrogen. Recently, a hydrogen colour convention has been used and widely accepted among research institutes, governments, and industries (see Table 3). An additional classification for hydrogen is given by the emission linked to its production (gCO₂/MJ_{H2}). In 2016, under the CertifHy project, FCH-JU established the threshold for low-carbon hydrogen at an emission factor of 36.4 gCO_{2-eq}/MJ_{H2} (CertifHy, 2019). The defined threshold was expected to be reduced annually following a declining path until reaching a point where only green hydrogen was produced.

Table 3. Hydrogen types in a colour scheme by technology and fuel

Type of Hydrogen	Production	Considerations	Emission Factor
Brown/ Black	 Produced through coal gasification. The colour depends on the type of coal used: brown (lignite) or black (bituminous) coal.	It is a highly polluting process since both CO ₂ and CO are not reused and, thus, released into the atmosphere.	19 tCO ₂ /tH ₂ (IEA, 2019)

²¹ A covalent bond involves the sharing of electron pairs between atoms in a molecule.

Type of Hydrogen	Production	Considerations	Emission Factor
Grey		Produced from fossil fuels, most commonly from natural gas through the SMR process. Less commonly it uses the ATR process	Although it is a mature technology, it involves notable disadvantages such as mass and heat transfer issues, as well as coke deposition during the reaction. 10 tCO ₂ /tH ₂ (IEA, 2019)
Blue		It is produced in the same way as brown or grey hydrogen, but its CO ₂ is captured and stored or used.	Depends on the availability of carbon storage (CCS) or carbon use (CCU). 0.64 – 0.99 tCO ₂ /tH ₂ (CE Delft, 2018)
Purple/ Pink		Obtained by electrolysis linked to a nuclear power plant.	It faces the public acceptance of nuclear plants and the phase-out plans defined by several Member States. CO ₂ free
Turquoise		Turquoise hydrogen is a by-product of methane (natural gas) pyrolysis, which splits methane into hydrogen gas and solid carbon.	It is highly energy-intensive. The current market will not be able to absorb the massive amounts of carbon black produced (Wiley-VCH-GmbH, 2020). CO ₂ free
Sunlight		It does not have yet an established colour to be classified. Produced by photocatalytic water splitting with solar energy, without going through the electrolysis step.	Several technologies are being developed but are still at the lab or small prototype scales. CO ₂ free
Yellow		Produced by water electrolysis utilising using the power of mixed origin from the grid (others refer to hydrogen produced from solar power)	Since the origin of the power is not carried, it could have a high CO ₂ emission factor associated. Power grid factor (gCO ₂ /kWh). Incurred T&D losses should be accounted for.
Green		It is produced by electrolysis of water, using solely electricity from renewable energy sources.	Availability of RES and water play a key role. CO ₂ free

Source: Own elaboration based on (IEA, 2019), (CE Delft, 2018), (Wiley-VCH-GmbH, 2020), and own analysis.

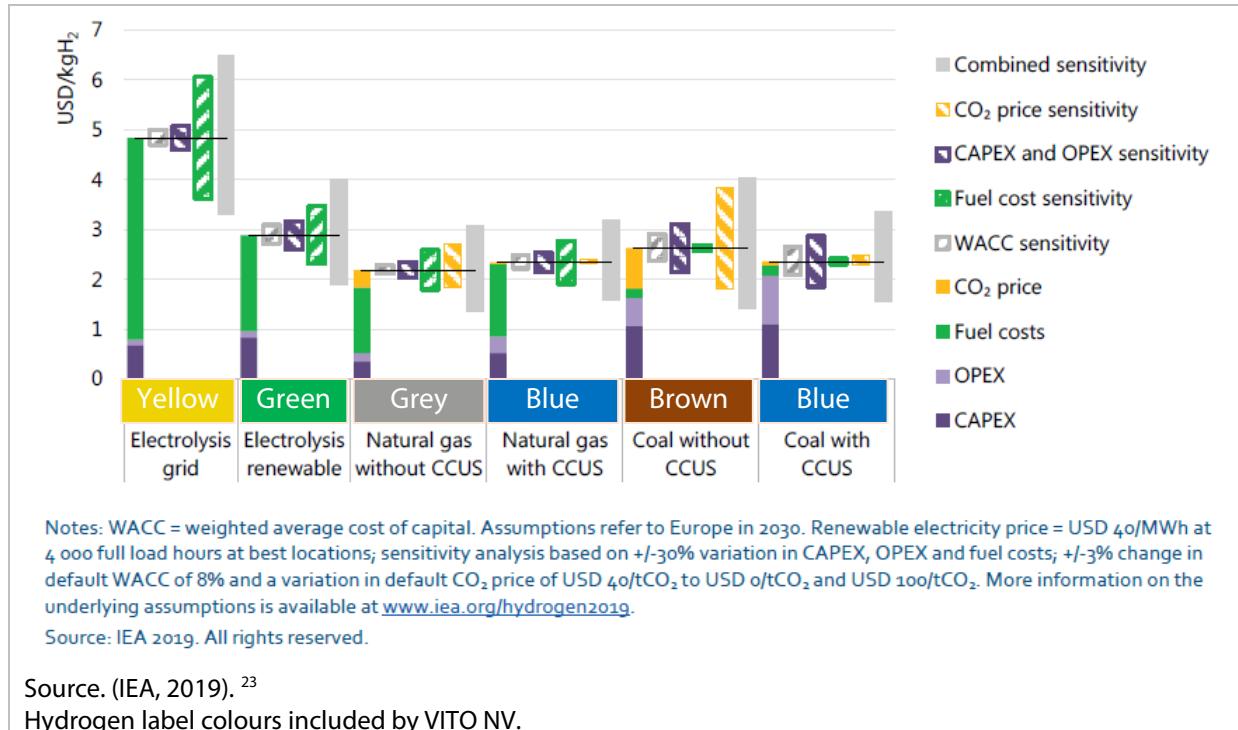
4.2. Supply of hydrogen

The production of low carbon hydrogen in the EU, either green or blue, depends on the availability of RES and the feasibility and potential of carbon capture and storage or utilisation, respectively. Considering the increasing hydrogen demand in Europe, which is expected to be 12-17 MtH₂ in 2030 and 20-57 MtH₂ in 2050²² (FCH-JU, 2019), and the potential of new wind and solar power generation installations, it is most likely that hydrogen imports will play a relevant role. Currently, Europe consumes approximately 9 MtH₂, which is to a large extend being produced by natural gas-based steam methane reforming. In this regard, Hydrogen Europe estimates that by 2030 Europe will

²² Based on the HHV of H₂ = 141.88 MJ/kgH₂.

import 3 MtH₂ -nearly 18% of its hydrogen demand- and will produce locally 7.4 MtH₂ (Hydrogen Europe, 2020). The share of imported hydrogen could increase in the long term if fossil-based hydrogen with carbon capture and storage or utilisation is not deployed in time to meet the remaining 9.5 MtH₂ that are expected to be covered by blue hydrogen by 2030 according to Hydrogen Europe.

Figure 23. Hydrogen production costs for different technology options in 2030



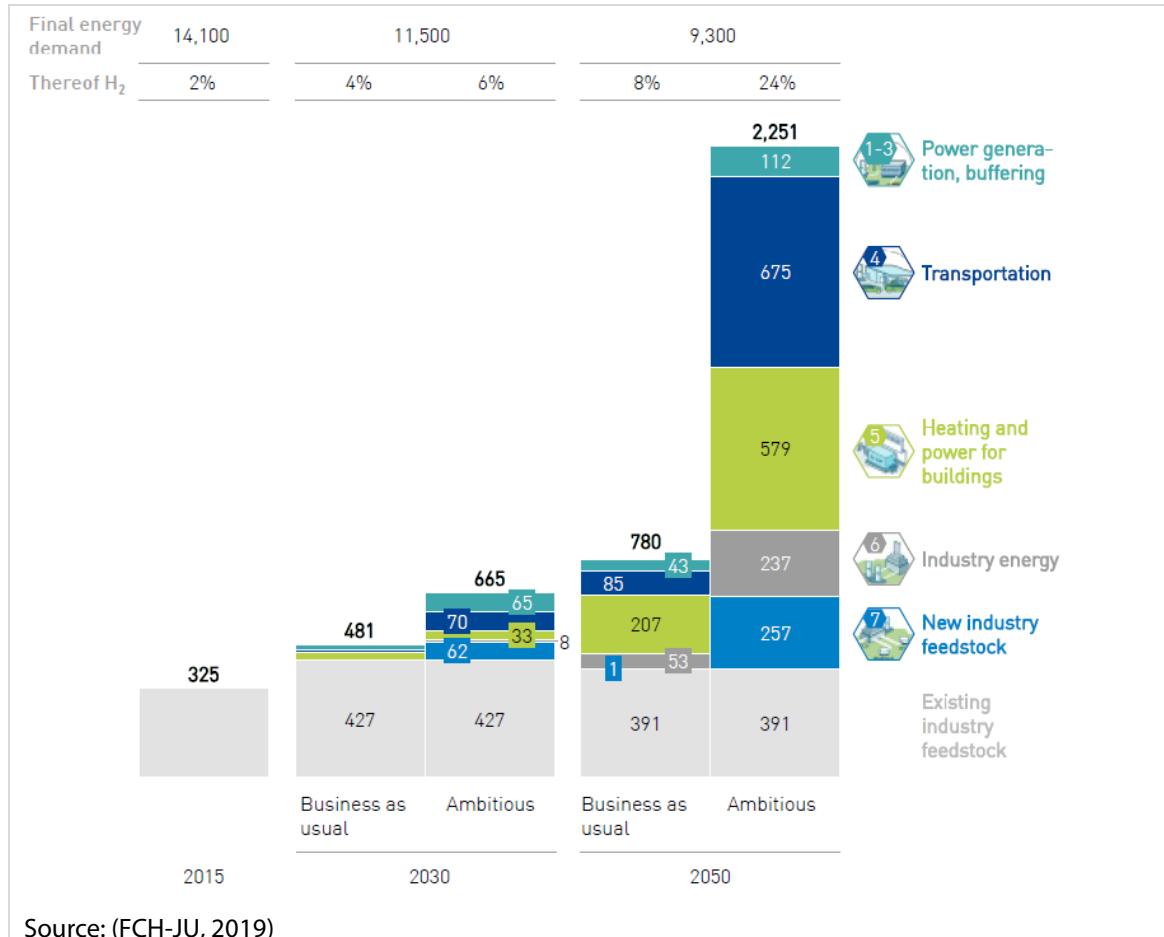
Future hydrogen production within the borders of the European Union is being championed by the 2x40 initiative while considering the potential of neighbouring countries in the North Africa region and Ukraine. The initiative envisions by 2030 the installation of 40 GW of electrolyser in Europe powered by 82 GW of wind and solar generation. It additionally foresees the rollout of 32.5 GW of electrolyser in the neighbouring countries which will be dedicated to exports to Europe (Hydrogen Europe, 2020). The European Commission mentions in its Hydrogen Strategy that it will be possible to produce 10 Mt of green hydrogen (333 TWh_{H2}) by 2030. This represents more than the hydrogen needed to completely produce 94 Mt_{steel} with the H-DRI route -this requires approximately 6.6 MtH₂. However, producing 10 Mt of green hydrogen means that 75 GW of electrolysers (the capacity envisioned in the 2x40 initiative), with an efficiency of 74%, will operate with green electricity around 6 000 hours per year – this without considering transport and storage losses and energy consumption.

To put the hydrogen needs of the steel sector with the H-DRI route (6-8 MtH₂) into perspective, the additional hydrogen demand forecasted by FCH-JU in its ambitious scenario for all hydrogen end uses is forecast to be 7 MtH₂ by 2030 and 56 MtH₂ by 2050. This is on top of 13 MtH₂ and 12 MtH₂ demanded by the existing industry for the same years (FCH-JU, 2019). In the same study, 1.9 MtH₂ are allocated to New Industry Feedstock in 2030 and 7.8 MtH₂ in 2050 (out of which 4.2 MtH₂ are indicated to be used in the steel sector in 2050 to produce 20% of the steel in Europe). Thus, if the

²³ CAPEX used in IEA 2019: Electrolysis = 647 €₂₀₂₀/kWe. SMR = 841 €₂₀₂₀/kW_{H2}. SMR with CCS = 1257 €₂₀₂₀/kW_{H2}.

production of primary steel continues to be 60% of the total production and it is fully produced with the H-DRI route, the demand for low-carbon hydrogen in the sector by 2050 could be 7-12 MtH₂.

Figure 24. FCH-JU vision on Europe's future hydrogen demand by sector



4.3. Hydrogen handling

For hydrogen to reach the end-use location, its transport, storage, and distribution should be carefully considered and planned. The development of the required infrastructure, which will be addressed in more detail in Chapter 5: *Hydrogen infrastructure*, depends not only on the hydrogen production sites or the hydrogen importing terminals but as well on the so-called hydrogen valleys. Such valleys aggregate several current and potential hydrogen users (e.g.: petrochemical industry, steel) in an industrial cluster within a defined geographical area. To better characterise such valleys and overcome the lack of information for the participants of the future hydrogen economy, the European Commission launched in 2019 the European Hydrogen Valleys Partnership²⁴.

By 2030, the members of Gas for Climate envision an initial hydrogen backbone in western-central Europe, around the already established industrial clusters in the Netherlands, Belgium, the west of Germany, and north of France (Guidehouse, 2020).

²⁴ Hydrogen Valleys website: <https://s3platform.jrc.ec.europa.eu/hydrogen-valleys>

5. Hydrogen infrastructure

Takeaways

- Europe has approximately 260 000 km of gas transmission and 1.4 million km of distribution pipelines. Compared to approximately 2 000 km of existing hydrogen pipelines. The natural gas grid is operated by different organizations across the EU with who can apply their experience to plan for transporting hydrogen on larger scale. The demand of hydrogen is estimated to be 1 130 TWh per annum.
- Converting selected parts of the existing natural gas grid for transporting hydrogen creates pathways for hydrogen producers, industrial off takers, operators and regulators to prepare for deep decarbonisation of hard to abate sectors such as iron and steel. The Hydrogen Backbone study envisions a network of 23 000 km of hydrogen pipelines of which 75% are repurposed natural gas pipelines.
- It is estimated that total cost spent for repurposing natural gas pipelines represents 10 - 20% of the cost of newly installed dedicated hydrogen pipelines (compression and storage infrastructure excluded). However, natural gas infrastructure will exist in parallel with hydrogen for a considerable time. Selected new hydrogen pipelines will have to be built in adjunction.
- Blending of hydrogen, 5%-20% with bio methane or natural gas is technically possible and can be made available at relatively low cost, however it comes with complex regulations and compatibility constraints in a European grid context while the impact on reducing carbon emissions is limited e.g.: blending in 10% green hydrogen results in 3% CO₂ reduction.
- Storage capacity to provide short and long-term backup, due to the intermittent nature of green hydrogen is an essential element of the European hydrogen infrastructure.
- Existing storage facilities in the form of salt caverns or depleted oil and gas fields are good candidates due to its relatively low cost (€6 - €26 MWh/H₂) but will have to be investigated further in terms of engineering safety and matched with the hydrogen needs of industry and other sectors.
- Large hydrogen of takers are often concentrated in industrial clusters, with high demands for hydrogen often as a fuel and feedstock, are some of the geographical hot spots in the European hydrogen backbone. They can exist as islands and might be interconnected where it makes sense.

Hydrogen infrastructure describes the physical links between the point of production and consumption. It comprises the long and short distance pipelines, transport by ship, road, terminal stations, long and short-term storage facilities and filling stations. Similar to roads, providing the means for cars to drive on, adequate and secure hydrogen infrastructure is essential in the mass roll-out of hydrogen in industrial, power, transport, food and process sectors. Currently, the existing hydrogen transport infrastructure is one of the main bottlenecks in the transition to sustainable hydrogen use in the EU.

Upscaling hydrogen in the European gas grid can be achieved by reusing existing natural gas infrastructure, blending to a certain extend hydrogen with natural gas and building dedicated hydrogen routes. This requires careful planning across the entire value chain. Specifically, for the steel industry, where hydrogen can be used both as an energy vector and feedstock, large amounts of green or blue hydrogen can help to reach the EU 2050 climate targets.

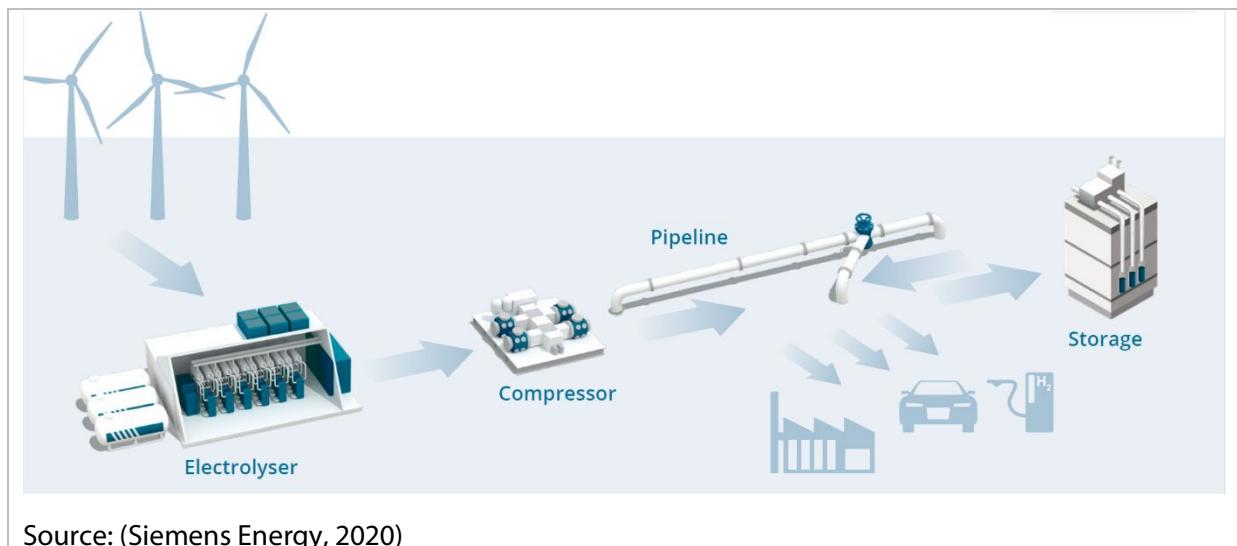
5.1. Transport of hydrogen

Regardless of the production method of hydrogen, as described in Chapter 4, the molecule will have to be transported as long as it is not used at the place of production. Costs for transmission and distribution of hydrogen could end up being three times higher, when building new infrastructure, compared to the cost of hydrogen production. In summary, hydrogen can be transported as a compressed gas or as a cryogenic liquid due to liquefaction (just below its boiling point of -252.9 °C). The cheapest method of delivery depends on the quantity delivered and the distance.

5.1.1. Pipelines

For distances below 1 500 km, transporting hydrogen as a gas by pipeline is likely to be the cheapest delivery option (IEA, 2019). This way, expensive liquefaction or high-pressure compression infrastructure, compared to transporting hydrogen by road or water, can be avoided. See Figure 25.

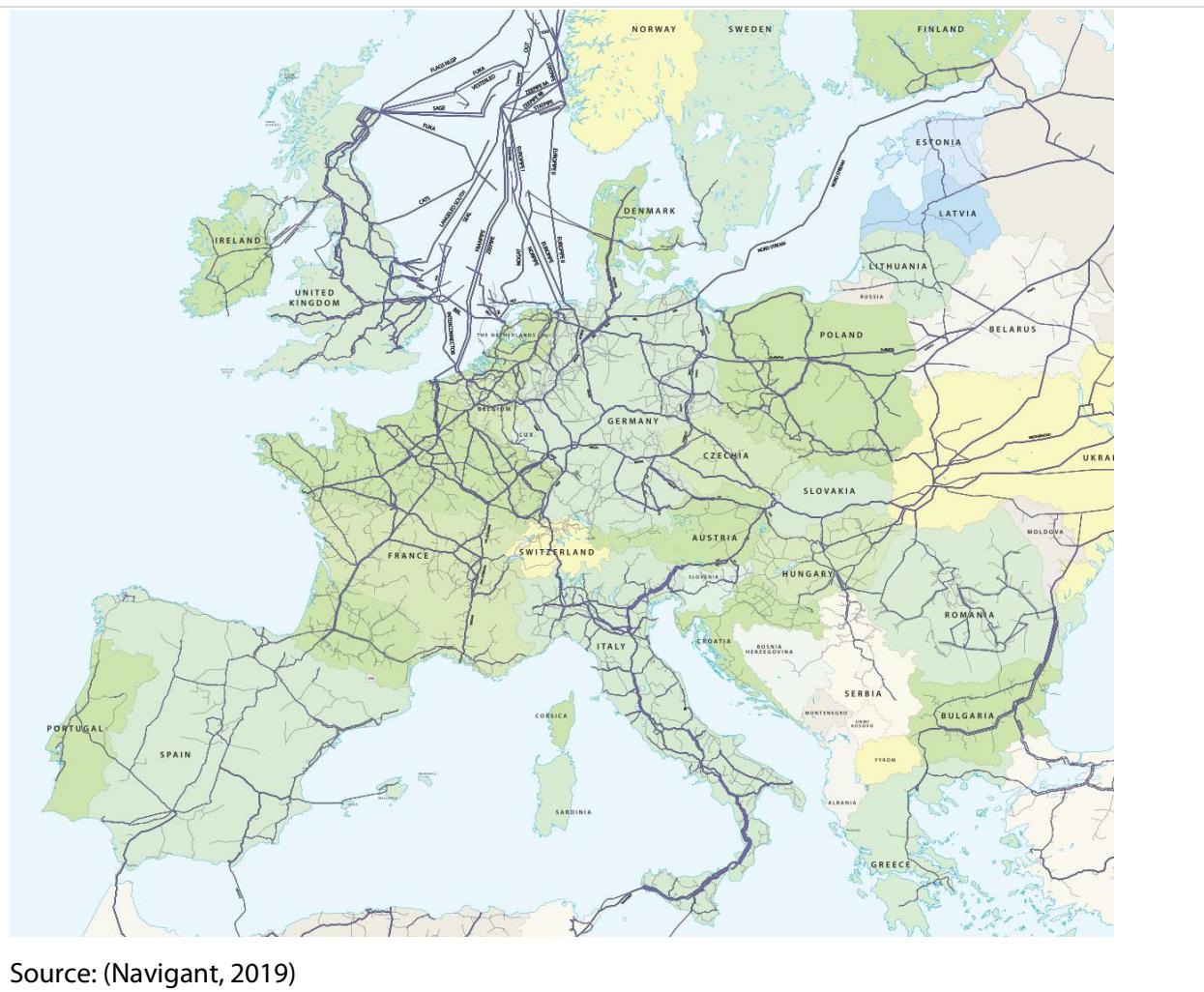
Figure 25. Hydrogen production and transport route using pipelines



Source: (Siemens Energy, 2020)

The requirements for a hydrogen pipeline line system has similarities with the existing natural gas infrastructure in Europe. Today, the European natural gas network consists of approximately 260 000 km of high-pressure pipelines which are operated by transmission system operators, and approximately 1.4 million km of medium and low-pressure pipelines operated by distribution system operators (Navigant, 2019) as shown in Figure 26.

Figure 26. Existing European gas network



When comparing the energy density of hydrogen (3 kWh/Nm₃), it is 3 times lower than the active component of natural gas, methane (10 kWh/Nm₃). This makes hydrogen very light. However, its LHV is roughly 2.5 times higher than methane. Hydrogen is a very compressible gas that can increase the energy density and makes it comparable with the energy density of natural gas. In gas form, hydrogen can be transported in large amounts through pipelines and stored in caverns or pore storage. A comparison in terms of energy volumes transported between the electricity grid and the gas grid is often made to point out the large differences and opportunities for using gas as an energy carrier. The gas infrastructure can transport between 10 and 20 times more energy over long distances than a high voltage electricity cable can as illustrated in Table 4.

Table 4. Cable versus pipeline energy transport examples

	Cable	Pipeline
Name	Cable (BritNed)	Pipeline (BBL)
Capacity	1GW	20GW
Construction costs	EUR 600M	EUR 500M

Distance	260 km	230km
Volume (year)	8TWh	120TWh
	Cable	Pipeline
Name	Cable (NEMO)	Pipeline (IUK)
Capacity	1000 MW	FWD (import BE): 27 153 MWh/h REV (export BE): 33 476 MWh/h
Construction costs	EUR 690M	EUR 713M
Distance	140km	235 km
Volume (year)	8TWh	240TWh

Source: (Hydrogen Europe, 2019)

There are various studies ongoing where transporting hydrogen through existing natural gas pipelines are tested. Both blending hydrogen and natural gas, as well as transporting of 100% hydrogen belong to the possibilities. This contributes to developing transition pathways towards the EU2050 climate targets, safeguarding existing assets and investments, whilst allowing for the industry to prepare for the next steps. Besides existing pipelines, most likely additional infrastructure would have to be built to facilitate future demand across all sectors. (Siemens Energy, 2020)

5.1.2. Shipping

Hydrogen can also be imported by ship. However, due to its low energy density, it will have to be liquefied by decreasing the temperature to below 240 °C., in combination with increasing the pressure. Energy requirements for liquifying hydrogen are greater than compressing hydrogen though, at very low temperatures, hydrogen takes more than ten times less space. Another means to transport hydrogen in large quantities overseas is by transforming it into a carrier with higher densities such as ammonia or in liquid organic hydrogen carriers (LOHCs). Once the hydrogen or carrier molecule arrives at a port somewhere in the EU, they can be loaded onto the gas grid and transported or temporarily stored. Using a different molecule than hydrogen as a carrier overseas makes hydrogen more cost-efficient due to the availability of large amounts of variable renewable energy sources. However, it requires special handling at the terminals to convert hydrogen into these carriers and back to hydrogen. These costs have to be taken into account as well as matters of safety and social acceptance. (IEA, 2019)

Finally, the transmitted hydrogen has to arrive at the point of use where it can be used as a source of energy or feedstock such as in the steel sector where hydrogen can play a role, as described in chapter 2.4.2 Alternatives pathways to decarbonise steel production.

5.2. Hydrogen Backbone

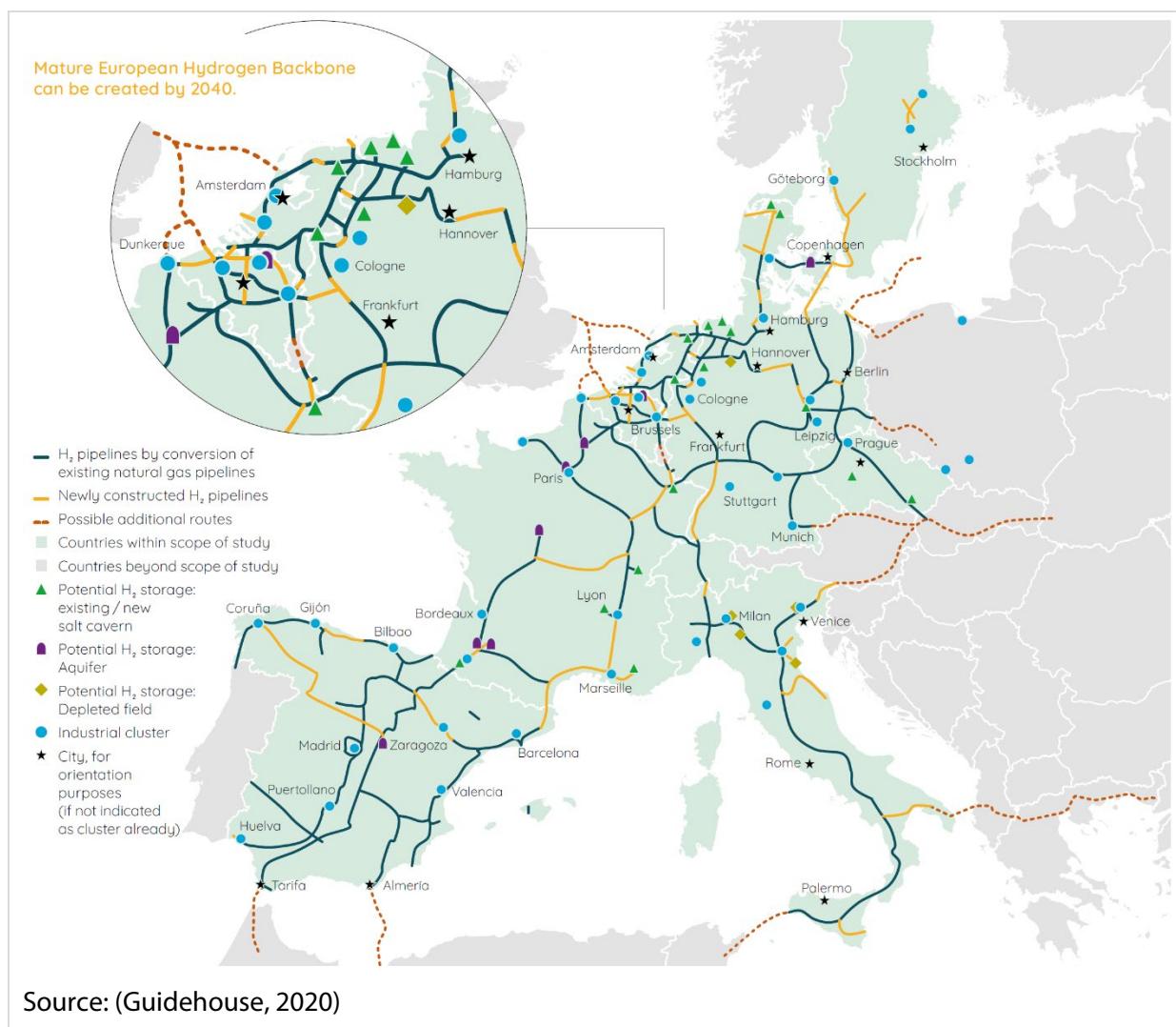
The EU gas network is well developed with a working gas volume of approx. 24.3 billion m³. The existing natural gas pipelines can play a key role in repurposing the gas transmission for hydrogen. Both in terms of time to build and investments, it presents opportunities to transition towards a climate-neutral hydrogen-based industry. Depending on the size and material, pipes of the natural gas grid could either be used in their current state or might require repurposed to cope with the higher pressure required to transport hydrogen and degradation of the iron and steel walls of the pipes due to hydrogen embrittlement. The latter can lead to cracks in the pipework. Most of the upgrades will have to take place on the compressor stations, valves, fittings, metering stations, and storage tanks. Though compared with building new pipelines, these costs are relatively small. The technical aspects differ by the location of the gas grid and the topography such as hills and

mountains. Besides the infrastructure cost, spatial planning, social acceptance, environmental and building permitting as well as regulatory procedures can be time and cost-intensive. These required steps could easily take five to seven years between planning and commissioning of the new pipeline. The existing gas pipelines, including their rights of way and use, are however available and generally accepted by the population. (Siemens Energy, 2020)

Existing gas grids often consist out of parallel pipelines which could be used to build scenarios of introducing hydrogen in a phased approach, aligned to demand and production volumes and technology development, as (Navigant, 2019) describe in their report Gas for Climate. Currently, EU gas transmission owners are conducting studies and tests to find out which parts of their infrastructure can be reused for transporting hydrogen. A projection of how a European hydrogen backbone could look like is shown in Figure 27.

On December 15th, a proposal to extend the existing framework for trans-European energy network (TEN-E) has been published in the European Commission. A revision of the current TEN-E allowing for changes in the gas landscape such as the production, transmission, distribution and storage is required. The next TEN-E version will also include dedicated new hydrogen infrastructure, repurposed pipes and connections with other countries. However, the proposal does not mention the option of retrofitting existing gas infrastructure for the purpose of blending hydrogen (European Commission, 2020). Studies such as the Thyga project, coordinated by Engie and eight partners from six other European countries (DGC, Electrolux, BDR, Gas.be, CEA, GWI, DVGW-EBI and GERG), are working together in this 36-month project which started in 2019 as part of the Fuel Cells and Hydrogen Joint Undertaking organisation. Its purpose is to get a better understanding of blending hydrogen with natural gas (Thyga, 2021).

Figure 27. Mature European Hydrogen Backbone



This idea of the hydrogen backbone has been developed by ten European countries (Germany, France, Italy, Spain, the Netherlands, Belgium, Czech Republic, Denmark, Sweden, and Switzerland) which host eleven gas transmission operators Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas (Nordion Energi), Teréga, and consultancy company Guide house (formerly known as Navigant). Its vision aims in the first phase to have 6 800 km of hydrogen pipelines available by 2030 and 23 000 km by 2040 of which 75% would consist out of reused natural gas pipelines. Due to its phased approach of rolling out the hydrogen backbone, dedicated hydrogen microgrids can emerge around industrial clusters. As the backbone develops over time, larger volumes of hydrogen can be transported within industrial clusters and their connections with other clusters as well as regional, national, and international connections. (Hydrogen Europe, 2019)

According to the Hydrogen Europe Backbone report (Guidehouse, 2020), one of the challenges is dealing with the diversity in operational gas pipeline sizes in Europe today, ranging from 20-inch pipelines to large 48-inch pipelines and even larger in some cases. Depending on the diameter but also the pressure applied, more or less energy can be transported. For instance, a 36-inch pipeline has a transport capacity of 7 GW and a 48-inch pipe has a capacity of 13 GW for the purpose of transporting natural gas. The capacity could be optimised to 17 GW in the case of hydrogen due to

higher flow rates. One backside is that increasing flow rates could lead to higher compressor costs. In some cases, for newly build stretches, it might be more economically advantageous to install a parallel pipeline with the same diameter rather than investing in more expensive compressors.

The electrolyser needs to be sized according to the demand for hydrogen which could lead to the pipeline having a larger capacity than the hydrogen the electrolyser is producing at its output pressure. For example, during the start-up phase of a new section of the hydrogen backbone, the demand for hydrogen might be low. However large-sized pipelines might already be installed to accommodate future demand. By running in low capacity mode, costs for compressors can initially be kept low until an increase in the flow of hydrogen is warranted by demand increases. Finally, when looking at the consolidated interconnected grid, the study from the hydrogen backbone envisions enough capacity to meet the total hydrogen transport demand by 2040 which is estimated to be 1 130 TWh annually. (Guidehouse, 2020)

Part of the EU hydrogen backbone includes storage. Hydrogen used in heavy industry, such as the iron and steel sector, mainly require intraday or intra-week storage. For small amounts of hydrogen storage, onsite pressurised tanks are often sufficient to ensure continuity whereas large amounts of hydrogen buffers require underground storage. (Guidehouse, 2020)

Besides the gas network, there are about 33 000 km of oil pipelines that could be re-used for hydrogen transport, depending on the future need for liquid fossil fuels, once they are no longer needed (Navigant, 2019).

5.3. Transmission and distribution

Currently, the natural gas grid consists out of long-distance pipelines with high pressure, between 15 and 80 bars, and distribution pipelines for shorter distances with pressure below 15 bars. Transmission pipelines are usually made out of steel to cope with the higher pressures and distribution pipelines are made of various materials like cast iron, PVC enriched polyethylene, fibre-reinforced cement or steel. Assuming large amounts of hydrogen are required for use in the steel industry, the focus of the next chapters lies on the transmission network.

5.3.1. Existing hydrogen network

Besides the natural gas grid, which is by size and coverage the largest gaseous molecules network, there are worldwide more than 4 500 km of dedicated hydrogen pipelines in total, mainly operated by private company Air Liquide. The longest pipelines are operated in the USA, in the states of Louisiana and Texas (2 608 km), followed by Belgium (613 km), Germany (376 km), France (303 km) and the Netherlands (237 km) (Europe, 2017). Figure 28 shows an overview of the largest no-natural gas infrastructure in the EU.

Figure 28. Existing no-natural gas pipelines in Europe



5.3.2. Repurposing

There is a strong indication that the natural gas network pipelines can be repurposed to transport hydrogen. Various studies and experiences of technology and material are showing that it makes sense to re-use at least part of the existing gas grid and can be implemented in a phased approach. Comparing repurposing with constructing new pipelines, the former lowers complexity and time to market. When comparing the energy flow of two gases through a pipeline, it is not only the volume that is important. Mainly values of density, flow velocity and pressure impact the amount of energy that can be delivered via a pipe. Since hydrogen has a density which is nine times lower and three times the flow rate of natural gas, almost three times the volume of hydrogen can be transported simultaneously in the pipeline at the same pressure. Therefore, the switch from natural gas to hydrogen has little impact on the capacity of a pipeline to transport energy. (Siemens Energy, 2020).

5.3.3. Compressors

Compressor stations play a vital role in transporting gas in a pipeline. Parameters of the viscosity of the gas as well as the velocity of the gas, combined with friction against the inner side of the pipelines and elevation distances, causes resistance of the flow and leads to a pressure drop. As the pressure in a pipeline has to be kept within certain ranges, recompression is needed. A gas that flows through a pipeline with lower capacity utilisation, which is the amount of hydrogen that passes through a compressor per unit of time, experiences a lower pressure drop thus requiring smaller compressors. This is an important parameter towards the sizing and costs of the compressors. Repurposing or retrofitting large transmission lines requires larger and more expensive compressors compared to smaller pipes. The distance between compressor stations is typically 100 km but can reach up to 600 km and depends on the size of the pipes, material, and landscape (Calisto, 2020).

The type and number of compressors in each compression station depend on the size of the pipelines. Currently, piston compressors are used – up to 750 000 Nm³/h, which are fed from the natural gas grid to which they are connected. For transmission of larger volumes per unit of time,

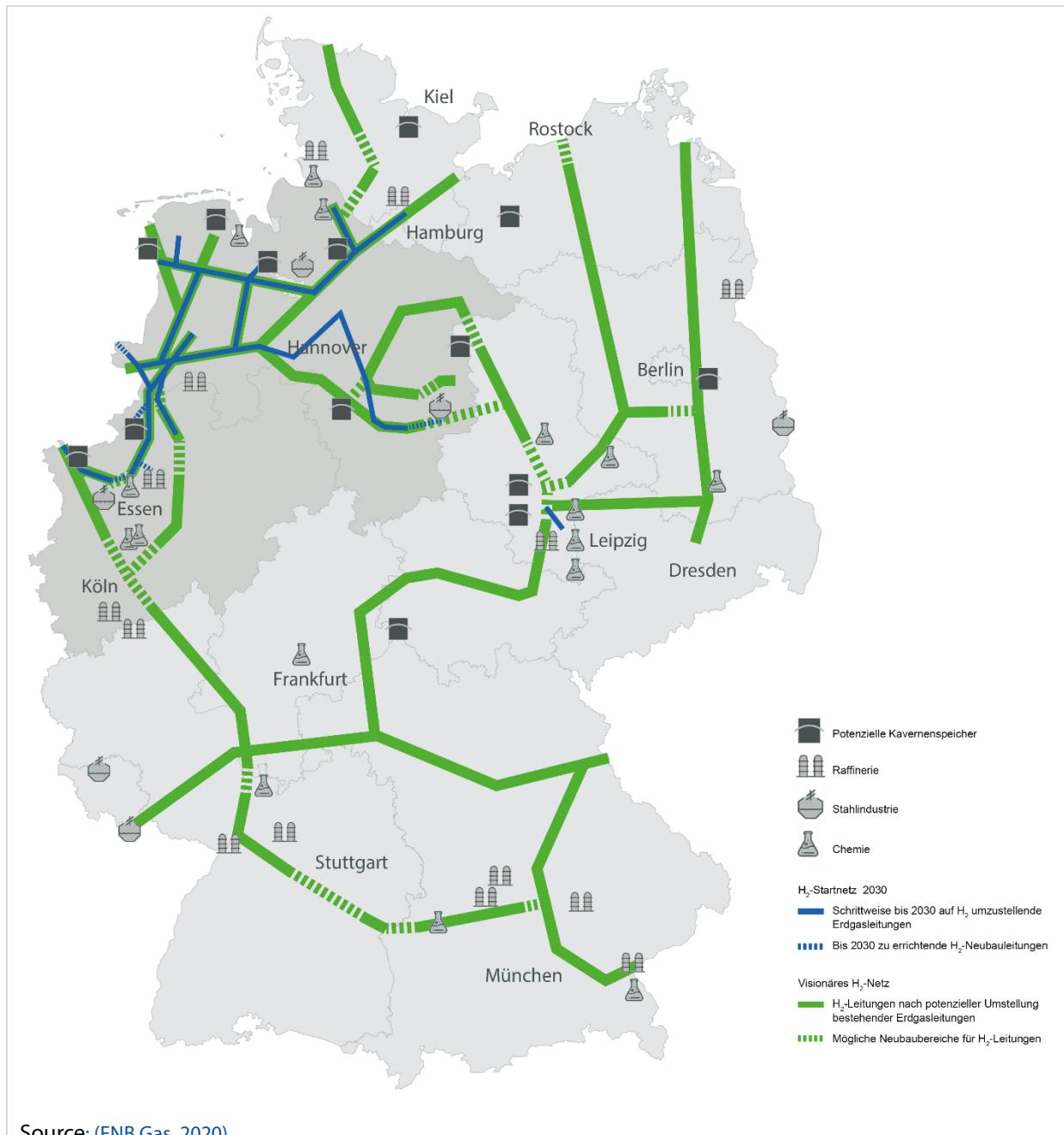
turbo compressors are needed. When using hydrogen, blended with natural gas or pure, they will have to be adapted to burn the hydrogen as an operating fuel. However, most common compressors can already handle a certain amount of hydrogen. When using more than 10% of hydrogen, typically the compressor needs to be retrofitted. In case more than 40% of hydrogen is used, the compressor needs to be replaced by an adequate model. As technology advances, this problem diminishes, and future compressors could be made 100% compatible with the use of hydrogen. (Siemens Energy, 2020)

Safety protocols, in case of emergency shut-off, will have to be revised as well as existing regulations within and across nations and network operators. Inspections prior to commissioning the retrofitted part of the grid have to be carried out and maintenance plans will have to be updated.

5.3.4. H₂ repurpose initiative in Germany

The Get H2 Initiative, together with FNB Gas as the main national gas and transport companies aims to establish a national hydrogen infrastructure in Germany. The plan is to build a 5 900 km hydrogen grid (see Figure 29). Industrial sites such as steel and chemical clusters can be connected to the network. Local hydrogen production from wind and solar as well as imports can feed the grid with hydrogen. The main objective is to repurpose 90% of the network by converting existing gas infrastructure to the hydrogen-based grid. It is estimated that this approach results in a total cost of 10-20% of the investment of constructing a new dedicated hydrogen network. This kind of initiatives are essential to get a better understanding of how an existing part of the European gas grid could technically and economically be optimised for the use of hydrogen.

Figure 29. National Hydrogen Backbone in Germany in 2030 –Proposed by FNB Gas



Source: (FNB Gas, 2020)

5.3.5. Transmission costs

Investment costs for new pipelines can vary significantly depending on location, material and regulation. Besides material, also the installation costs are determined by the type of pipeline. Typically, two methods are used for installation. Trenchless pipes, where a tunnel is bored or drilled, which is generally cheaper than cut-and-cover pipes which are usually built in segments. The great diversity in pipelines materials, utilisation capacities, compressor stations, blending %, the grade of repurposing existing pipes, distances but also the geographical spread and volumes of (future) supply and demand make it difficult to make estimations on the final cost of the hydrogen backbone. An overview of investment cost ranges and the Leverage Cost of Transmission for repurposing existing versus new pipelines are shown in Table 5.

Table 5. Costs for repurposing or replacing gas network transmission

Component	Value (2019)	Comment	Source
Investment repurposing existing pipelines	M€ 0.37/km	Germany based case, cost of repurposing 15% compared to the new pipeline (excl. compressors).	[1]
Investment cost new pipeline (range)	M€ 0.93/km M€ 2.1/km M€ 3.28/km	16-inch average diameter. Costs for transmission of 6 300 km in the UK. The 48-inch pipeline, operating between 30-80 bar with a length of 300 km in the UK. 48-inch pipeline. (excl. compressors)	[2] [3] [4]
Investment New compressor (range)	M€ 0.65/MW M€ 1.07/MW	Costs for a 5.8 MW compressor, with a 240 t/day throughput. 5.8 MW capacity for compressor, calculated according to cost curve in source (compressors are required every 100-600 km, highly case-specific)	[5] [4]
LCOT for H2 transmission – repurposing natural gas infrastructure	M€ 3.7/MWh H2 per 600km	Repurposing existing gas infrastructure for 100% hydrogen.	[6]
LCOT for H2 transmission - New natural gas infrastructure (range)	M€ 4.6/MWh H2 per 600km M€ 11.4/MWh H2 per 600km M€ 45/MWh H2 per 600km	48-inch pipeline. Includes pipeline and compressor CAPEX and OPEX and compression fuel-related costs. Transportation over 1500 km is assumed by source, considering all capital and operating costs. Normalised to 600 km. Estimated including compression costs for pipes of diameters between 7-10 inches over 100 km as assumed by source. Normalised to 600 km.	[6] [7] [8]

Sources: 1. (FNBGas, 2019), 2. (Element Energy & E4Tech, 2018), 3. (Navigant, 2019), 4. (Jacobs, Element Energy, 2018) , 5. (Baufumé, 2012), 6. (Navigant, 2019), 7. (IEA, 2019), 8. (DNV GL, 2019).

Note: LCOT, Levelised Cost of Transmission

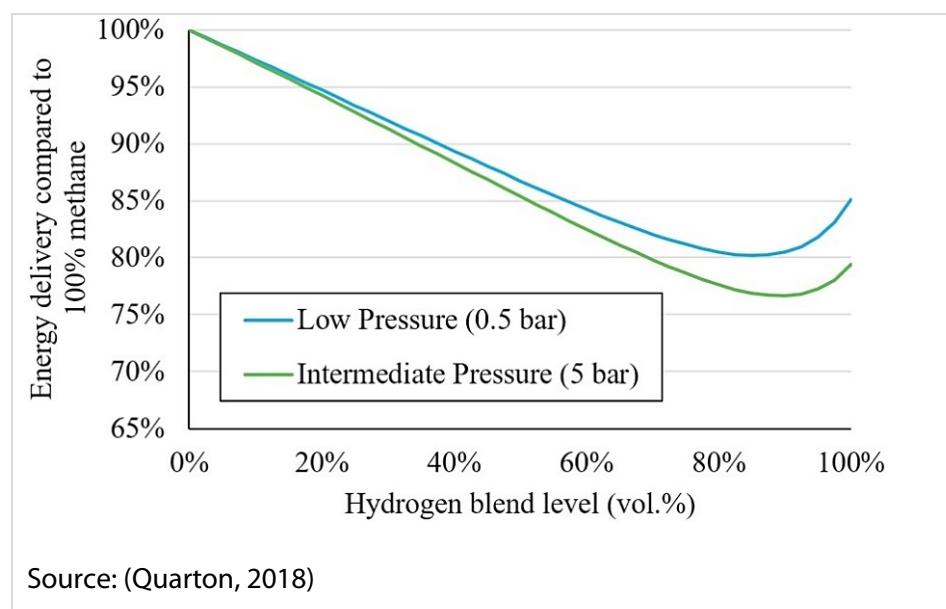
5.4. Blending and retrofitting

Hydrogen can be blended with methane in the natural gas network at limited percentages of 5%-20%, higher shares of up to 30% are being investigated. However, the latter involves blending 30% of locally produced hydrogen into a 840 MW Power plant in Los Angeles, USA as part of an island gas network connected as well to underground storage. Blending percentages are case-specific and may enable decentralised renewable hydrogen production in small amounts and local networks

during a transitional phase. However, when larger volumes of hydrogen need to be transported in combination with less natural gas, it makes more sense to use the dedicated route as blending becomes less efficient and reduces the energy delivery of the pipeline thus the value of hydrogen and might require expensive retrofitting of the pipes. (IEA, 2019)

The level of blending hydrogen and natural gas is mainly directed by the energy density by volume and the flow properties of hydrogen. Though hydrogen as a gas is highly compressible, it is less compressible than natural gas and the effect of reduced energy delivery becomes more pronounced at higher pressures. Figure 30 shows the energy delivery of pipelines, at low and intermediate pressure levels, with increasing levels of hydrogen injection as a percentage of the energy delivery of pure methane. In order to manage the reduced energy delivery in gas networks, either peak energy demand would need to be reduced, or higher flowrates would be needed. This would lead to pressure drops which in turn requires higher, more costly compression infrastructure. (Quarton, 2018)

Figure 30. Effect of hydrogen blend level on the energy delivery of gas pipelines



Source: (Quarton, 2018)

According to the (European Commision, 2020) Hydrogen Strategy report, blending might degrade the quality of the gas consumed and the variety of end-user gas applications such as in the European steel sector. Both the design of the infrastructure and interoperability between the Member States might be affected. This might lead to the fragmentation of the internal market when different standards of blending and transport of mixed hydrogen and natural gas are accepted by Member States. It is recommended to investigate the technical feasibility of different blending scenarios and their related costs to get a better view of the risks involved. This will most likely lead to revising applicable standards and regulations in each Member State as well as the European Committee for Standardisation (CEN).

Important to highlight is the effect of blending on the carbon content. Since Hydrogen has a volumetric energy density three times larger than natural gas, the effect of e.g. blending 10% of hydrogen will lead to a limited carbon emission reduction of only 3%.

Safety hazards related to hydrogen blending can range from hydrogen leakage in confined spaces to explosions which have been described in studies and are limited to cases of low % blending

(under 20%). They increase substantially, however, when more than 50% of hydrogen is mixed in the natural gas network. When commissioning a 100% dedicated hydrogen infrastructure, it is assumed that appropriate safety measures have been taken into account by design. (Melaina M.W, 2010)

An initiative started by the largest natural gas pipeline operator in Europe, Snam in Italy in 2019, investigates blending hydrogen into a transmission network in Europe. 5% of hydrogen was added and delivered to a pasta factory and a mineral water bottle company as fuel for heat. In a second stage, the percentage of hydrogen was increased to 10%. "If the gas flows continuously at a predefined pressure, the pipeline under testing could deliver 0.63 MMT of hydrogen per year, equivalent to 1% of deliberately produced hydrogen in 2018." These types of projects prove that it is possible, to introduce hydrogen in an isolated part of the natural gas grid, under certain conditions (BNEF, SNAM, IGU, 2020). However, making forecasts of a pan-European blended hydrogen rollout based on this example is another level. It would require a complete end-to-end approach, where all the components of the grid and its users, including regulatory bodies, will have to be involved.

5.5. Storage of hydrogen

Increasing volumes of hydrogen coming from variable renewable energy sources will not be available at constant rates. Due to the intermittent nature of solar PV and wind, storage capacity is needed to deal with hourly, daily, and seasonal fluctuations. Depending on the scale of consumption in various sectors of the hydrogen value chain, a matching storage capacity applies. In the natural gas market, storage in Europe and Ukraine have proven to be essential for balancing the LNG market in the past. Similarities can be made for a hydrogen-based grid (BNEF, SNAM, IGU, 2020).

For low volumes of hydrogen applications, hydrogen can be stored in tanks with high discharge rates and efficiencies. When compressing hydrogen at 700 bars, the energy density is only 15% of gasoline. Meaning, hydrogen tanks will have to be more than 6 times larger. (IEA, 2019) Likewise, with shipping, besides liquefying hydrogen and very low temperature, hydrogen can be converted to other molecules and stored in tanks, at certain costs and energy losses. Large scale applications of hydrogen, such as industrial clusters and transport overseas, require different storage techniques. Prior to loading a ship with hydrogen, storage might be needed to bridge short periods while the ship prepares. Long duration storage facilities are required to overcome seasonal shortage if hydrogen were to be used as feedstock supply or heat demand to provide continuous operations for industries. Finally, the geographical spread of hydrogen production, transport, storage, and use will also play an important factor in the design of adequate storage facilities across the EU.

Besides storing hydrogen underground or in tanks, the pipelines used for transport act as storage. Depending on the pressure, the diameter of the pipes, and the length of the network, large amounts of hydrogen are stored. Example: 2 000 km pipeline at 100 bars of pressure with a width of 35 inches can store approximately 130 GWh of hydrogen, assuming constant flow rates. However, these are ideal conditions. In reality, hydrogen will most likely be produced decentral across the EU at different pressures and flow rates resulting in fluctuating storage across the grid.

5.5.1. Storage in tanks

Pressurised tanks are the most cost-efficient and available technology for storing limited amounts of hydrogen, up to 1 100 kg (33.6 MWh). These types of tanks are commonly used across the hydrogen value chain and can be sized and strengthened relatively easily. Storing liquefied hydrogen in a tank reduces the volume but is more complex and costlier due to the energy required for the conversion from gas to liquid state at very low temperatures (-252.9 °C). This method, also called cryogenic storage, consists out of cooling down the gas to at least -239.96 °C and compressing it in several steps. In the first step, pure hydrogen gas is compressed. This causes the temperature of the hydrogen gas to rise. Next, the hot gas is passed through two heat exchangers and mixed to be

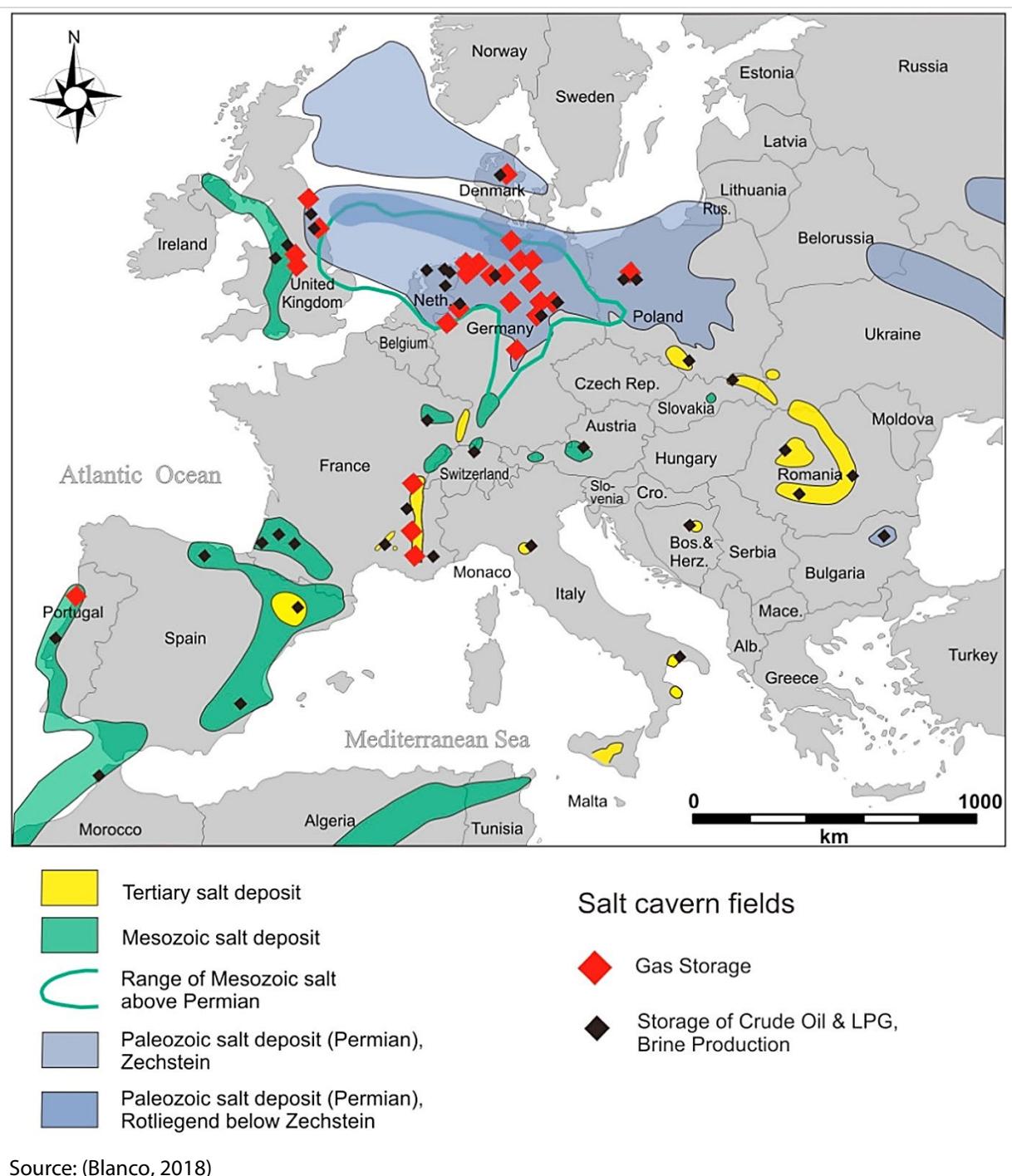
passed through a tank containing liquid nitrogen. In the last step, the cooled gas is passed through another heat exchanger to reach its final temperature. The entire liquefaction process consumes about 30% of the energy in compressors and coolers, which is available in the hydrogen.

5.5.2. Underground storage

Storing large volumes of hydrogen requires large deposits as it takes more than three times more space than natural gas for the same amount of energy. The main difference between storing natural gas underground is its purpose of providing long-term security of supply whereas, in the case of hydrogen, it serves as a solution for short to mid-term energy balancing. Depleted gas or oil fields on land or at sea, excavated rock caverns, aquifers (or pore storage) and salt caverns are the most common geological storage locations for storing gases. Salt caverns have the lowest total cost due to their natural behaviour of trapping gas effectively, are strong and do not degrade easily over time. What salt caverns lack in storage capacity compared to an empty oil or gas field, is compensated by increased flexibility to deliver. The simple and robust design of these caverns makes them more reliable for rapid filling and withdrawing, which is a favourable property in an intermittent renewable energy world. Depleted gas or oil reservoirs and aquifers require more careful analysis and preparation to make sure proper locking mechanisms are in place to prevent gas leaks. Besides gas volume losses through cracks in the structure, special care has to be taken into account when repurposing depleted gas fields, caverns or aquifers for storing hydrogen in pure or blended form. Corrosion and weaknesses in the sealings of the borehole can occur due to the formation of hydrogen sulphide which is caused by microbiological reactions within the aquifer. Bacterial growth can lead to further volume losses. A study run for the Netherlands Enterprise Agency dives deeper into the risks of storing hydrogen underground. (DBI Gas- und Umwelttechnik GMBH, 2017)

Figure 31 indicates the availability of various geological storage areas across Europe. Although there is no accurate number available to indicate the storage capacity available, some countries are investigating their potential. Germany, for example, has an estimated capacity of 9.1 billion m³ of pore storage and 17.6 billion m³ of cavern storage in the north of the country. This would cover storing the entire natural gas consumption of Germany for three months (Siemens Energy, 2020). In the north of the Netherlands, the HyStock project is planning to demonstrate the production of hydrogen and storage in depleted gas fields.

Figure 31. Underground salt deposits and cavern fields in Europe



5.5.3. Storage cost

Table 6. Costs for hydrogen storage

Investment Costs			
Technology	Range (2019)	Comment	Source
Depleted gas field	€280 - 424 /MWh H ₂ stored	CAPEX including compressors and pipes, 4% OPEX.	[1]
Salt caverns	€344 /MWh H ₂ stored	CAPEX for 1,160 t of working capacity (+1/3 additional for cushion gas), but highly dependent on geography. 4% OPEX, includes compressors and pumps.	[1]
Rock caverns	€1 232 /MWh H ₂ stored	4% OPEX.	[1]
Levelised Cost of Storage			
Technology	Range (2019)	Comment	Source
Tank	€0.17 kg H ₂ €4.1 kg H ₂	Compressed state hydrogen at 5 – 1 100kg per container Liquid state hydrogen at 0.18 - 4 500t H ₂ per tank	[1]
Depleted gas field	€51 - 76 /MWh H ₂	Cost for working gas capacity, 1 cycle/year. Including the cost of compression and pipelines needed for the facility to function.	[1]
Salt caverns	€6 - 26 /MWh H ₂ €17 /MWh H ₂	300-10,000 t per cavern, lower bound: monthly cycling, upper value: bi-annual cycling.	[1] [2]
Rock caverns	€19 - 104 /MWh H ₂	300-2,500 t per cavern, lower bound: monthly cycling, upper bound: bi-annual cycling.	[1]

Sources: 1. (BNEF, 2019), 2. (IEA, 2019)

5.6. Alternative transport and storage methods

Besides the main principle of transport and storing routes of hydrogen described in the previous chapters, several other means and technologies could become interesting in a specific context.

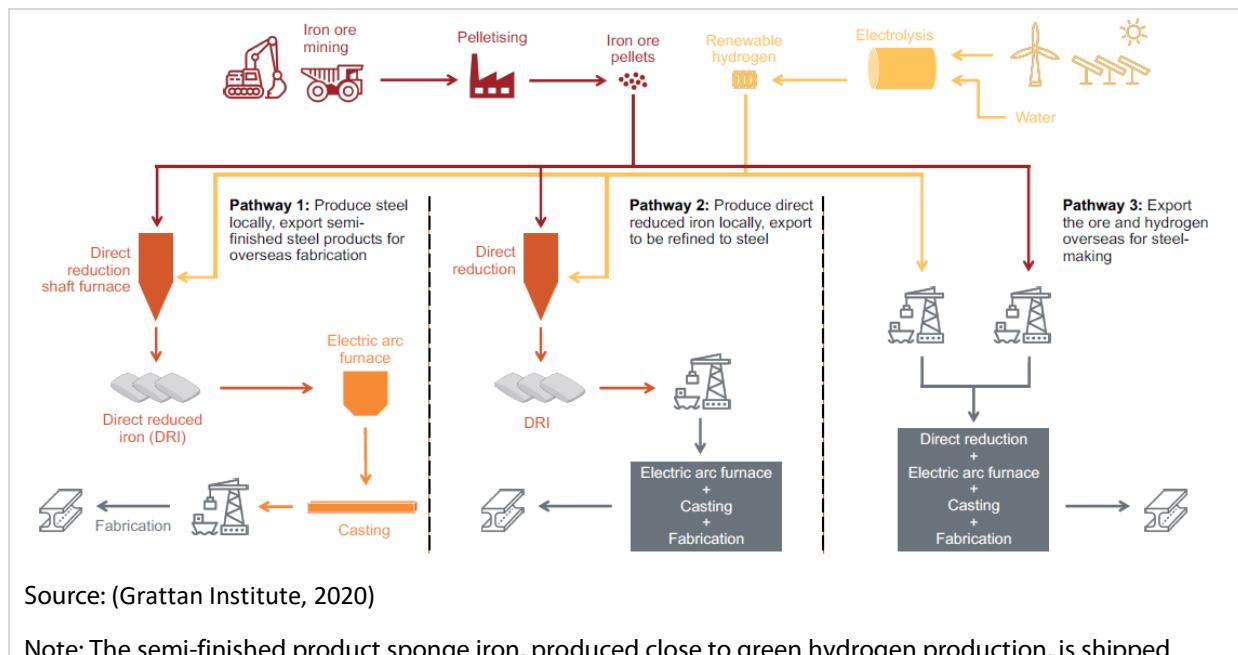
5.6.1. Sponge iron

In the production of Direct Reduced Iron, sponge iron is the output product of the reduction of iron ore with natural gas. In emerging technologies, reducing iron ore with hydrogen is tested. In both cases, hydrogen is stored during the reduction process. The sponge iron can be reacted in a later stage with steam to extract the hydrogen, which can be used for other purposes, and iron ore.

Another approach is to ship H-DRI sponge hydrogen instead of the green hydrogen or carrier molecules. This way, the sponge iron can be produced close to low-cost green hydrogen locations

and shipped to the location where the EAF further processes the sponge iron into steel and steel finishing, potentially at a lower cost and less complexity. Figure 32 shows a possible route in a study done for the Australian steel sector.

Figure 32. Possible routes for steel making instead of hydrogen shipping



5.6.2. Metal hydrides

Metal hydrides create chemical hydrogen bonds with other elements and can store hydrogen up to 6%. At low pressure, these hydrides absorb hydrogen which can be released at a later point by applying heat. There is a large range of elements and alloys that can be used. Though a few percentages of hydrogen can be captured, the effect in volume is significant. Shipping these metal hydrides requires special vessels that keep the atmospheric and temperature conditions stable.

5.7. Geographical hot spots

The development of the hydrogen pipeline infrastructure across Europe has two main drivers. On one hand, the location of the production sites within Europe and the shipping terminals to handle with hydrogen carriers (e.g.: ammonia, methanol, methane, LOHC) and on the other hand, the locations of the consumption, which are likely to initially be highly concentrated industrial hubs (chemical clusters, steel sector, manufacturing sectors) or major consumers. Hence, the transport distances will play a decisive role while prioritising the construction of one pipeline over another to connect two different points of the future hydrogen network.

In case hydrogen carriers are used during shipping, they will have to be converted back to hydrogen at or close to the port before being transported via the hydrogen backbone. Ammonia, for example, causes stress corrosion in steel and requires specific infrastructure and handling, different from hydrogen or methane. Moreover, industrial takers of hydrogen would be burdened by having to invest in reconversion facilities.

The future hydrogen backbone for Europe needs to be carefully planned since the transport of hydrogen implies challenges such as safety, pressure, and the techno-economic challenges of

repurposing the existing natural gas (as was addressed in section 5.3). The existing gas grid currently reaches the main industrial hubs, which will be most likely the initial hydrogen valleys. Then, leveraging on this already deployed infrastructure might reduce costs and ease the planning of the hydrogen backbone. It is relevant to take into account the development of larger-scale hydrogen storage facilities and the parallel development of a CO₂ infrastructure to enable CCU or CCS, which is expected to have an important role in the decarbonisation of Europe. However, there is also the need for policies that boost the creation of these hydrogen valleys in the current locations -which in most cases have also a privileged geographical location concerning the complete value chain- and the creation of new geographical hot spots to facilitate the development of hydrogen pipelines and large-scale storage facilities.

6. Conclusions

The iron and steel sector is one of the most challenging sectors to decarbonise among the energy-intensive industries in Europe, while at the same time being one of the pillars of the European industry and job market. In Europe the production of crude steel is currently at around 157 Mt, accounting for 4 % of GHG emissions.

Approximately 60 % (94 Mt) of total European steel production originates from the coal-based blast furnace/basic oxygen furnace (BF/BOF) route and is more suitable for the hydrogen direct reduction route (H-DRI). The authors of this study estimate that 94 Mt of 'green steel' would require approximately 37-60 GW of electrolyser capacity, producing approximately 6.6 Mt of hydrogen per year. As a reference, the EU hydrogen strategy aims to have 40 GW of electrolyser capacity installed within the EU by 2030. The authors estimate that these electrolyzers would consume approximately 296 TWh of green electricity per year; as a reference, Germany produced in total 176 TWh of green electricity in 2020.

Currently, the existing hydrogen transport infrastructure is one of the main bottlenecks in the transition to sustainable hydrogen use in the EU, where there are roughly 2 000 km of dedicated hydrogen pipelines located in four Member States, compared with approximately 260 000 km of natural gas pipelines. EU gas transmission owners are conducting studies and tests on which components of their infrastructure can be reused for transporting hydrogen. A most likely approach will be the creation of so-called hydrogen valleys to serve and connect regions of energy-intensive industrial clusters or the Europe Hydrogen Backbone initiative aiming in the first phase to have 6 800 km of hydrogen pipelines available by 2030 and 23 000 km by 2040, of which 75 % would consist of reused natural-gas pipelines. Most of the upgrades will involve compressor stations, valves, fittings, metering stations and storage tanks.

The transformation of the iron and steel sector has to be viewed in a broader context. Other energy-intensive sectors face similar challenges, albeit with different possible technology pathways. Therefore, an integrated approach to evaluating the potential decarbonisation pathways for all European industries is required, also looking at the real potential of industrial symbiosis opportunities, such as exchange and re-use of heat and products between industrial installations. This broad understanding of mid-term (2030) and long-term (2050) industrial energy and material needs can then be integrated in energy system analysis tools covering all sectors of the economy.

Here, the authors' team would also refer to the AidRES project – advancing industrial decarbonisation by assessing the future use of renewable energies in industrial processes,²⁵ which was launched in January 2021 and which will create a database for the main EIs in Europe, including current and future energy and feedstock needs, and map out renewable energy needs in high spatial resolution.

²⁵ Aid RES – Advancing industrial decarbonisation by assessing the future use of renewable energies in industrial processes, NUMBER –ENER/2020/OP/0011-C2/SER/2019-569/SI2.840687, (Pilot Project No. 32027714 of the European Parliament) - Project Officer: Eric Lecomte (DG ENER), Consortium Project Manager: Frank Meinke-Hubeny (Vito)

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Annex: Techno-economic assumptions

Parameter	Unit	2020	2030	2050	Source
Biomass	M€/PJ	7.99	8.42	9.69	Heat Roadmap Europe (European Commission, 2017)
Coal	€/t	26.9	18.4	18.1	IEA-The Future of Hydrogen (IEA, 2019)
Electricity	€/MWh	58	66	46	VITO NV
Hydrogen	€/kgH2	4	3.1	1.1	BNEF (BNEF, Snam, IGU, 2020)
Lime	€/t	62.5	62.5	62.5	European Lime association website
Natural Gas	€/MWh	24.8	27.1	26.8	IEA-The Future of Hydrogen (IEA, 2019)
Steel scrap	€/t	220	220	220	(MEPS Ltd, 2020)
CO ₂ Price (EU ETS)	€/t	25	84	160	IEA Energy outlook
Iron Ore	€/t	145	145	145	(Trading Economics, 2020)
CCS	€/t	85	85	85	(Toktarova, et al., 2020)
Electrolyser	€/kWe	450	208	144	Hydrogen import coalition and Hydrogen Europe
Short distance pipeline	M€/km	1.61	1.61	1.61	Hydrogen generation in Europe (European Commission , 2020)
Operating hours	h/yr	8 000			
Electrolyser efficiency	%	64%	67%	74%	Hydrogen generation in Europe (European Commission , 2020)
Electrolyser lifetime	h	80 000	80 000	90 000	Hydrogen generation in Europe (European Commission , 2020)
Stack cost (% CAPEX)	%	40%			
Discount Rate	%	5.40%			

The steel sector is one of the most challenging sectors to decarbonise and has recently received special attention owing to the potential use of low-carbon hydrogen (green and blue) to reduce its fuel combustion and process-related carbon emissions. This report addresses concerns that might arise while evaluating the potential and limitations of the future role of hydrogen in decarbonising the iron and steel industries.

The report provides a comprehensive overview of current technical knowledge, (pilot) projects and road maps at national and EU level. This information is supplemented by previously published indicative price projections for the various steel production routes and a long-term study, analysing the evolution of the global steel sector up until 2100.

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